142-144

NUCLEAR POLICY REVIEW
BACKGROUND PAPERS

1980

REPORT No. ER81-2E

Cat. No. M 23-14/81-2E

ISBN 0-662-11592-9

1

TABLE OF CONTENTS

FOREWORD

Virtually no activity society engages in is without risk. In this respect, questions about nuclear energy are not significantly different from those associated with any industrial or energy-related activity - all involve balancing economic and industrial benefits with actual and potential risks to the natural environment, to public health and safety, and to future generations.

In one way, however, nuclear energy is unique. Of all energy options it is the most controversial, the debate surrounding it the most intense and the issues involved most fundamental, ranging from health impacts on future generations to the type of industrial society which Canadians wish to see evolve over time. It is also the energy option for which the views of the physicist and engineer diverge most radically from the perceptions of the public.

In addressing nuclear issues it is useful, at the outset, to distinguish between two different types of questions which are often intertwined in the nuclear debate. The first are what might be termed questions of fact: just what are the risks posed to public health by nuclear energy? how attractive is it from an economic perspective? what are the risks of a nuclear accident? In many cases answering such questions is not a simple matter, and there are disagreements about what the factual answers are.

The second set of questions are what might be termed judgemental questions: are the small risks of a nuclear accident acceptable in terms of the economic benefits nuclear energy may generate? are potential impacts on future generations ethically defensible? With respect to these questions no clear cut answers are possible. Subjective judgements vary from individual to individual.

This collection of papers is intended to address the first set of questions, to provide a factual basis for the discussion of the broad range of issues which have emerged in the nuclear debate.

Each represents an attempt to summarize what is known about individual aspects of the nuclear debate, and where possible to establish the reasons why a range of answers to some questions may be possible.

If this volume has a common theme, it is that nuclear energy cannot be assessed in isolation. Rather, it must be judged in terms of its potential contribution to satisfying energy requirements relative to other means of achieving the same goal: broadly defined these include other conventional generating technologies, unconventional alternatives such as solar, wind and biomass, and energy conservation.

The volume begins, therefore, with a general discussion of demand for electricity. It is the demand for electricity in relation to the conventional and unconventional generation alternatives as well as conservation which determines the potential need for nuclear energy as a generating alternative.

The next papers turn to the economics of alternative ways of meeting load growth: load managment by marginal cost pricing; the economics of adding to capacity using conventional sources such as coal or nuclear energy; and a discussion on unconventional sources such as solar and biomass. Following this, a number of papers address the environmental, health, and safety aspects of the use of coal, hydro, and nuclear generating sources. The series then turns to more specific nuclear issues such as safety regulations, domestic and export problems, and finally international concerns such as Canada's role in the development of international non-proliferation agreements. Finally, there is a summary of the financial involvement of the federal government in the continuing development of the nuclear industry in Canada.

These papers have been prepared by officials in a number of government departments and agencies including Energy, Mines and Resources, External Affairs, Environment, Financing, Industry, Trade and Commerce, and the Atomic Energy Control Board. While they have been reviewed by an Interdepartmental Committee of Officials, there has been no attempt to standardize them with respect to style, length, and subject.

Although the publication of even background papers in an area such as nuclear policy is likely to generate some controversy, it is the government's view that the solution to these problems, whether real or perceived, is more, rather than less, information. These documents are put forward in that spirit and they should be accepted for what they are -- working documents prepared by officials to increase the public's understanding of some difficult issues.

FORECASTS OF DEMAND FOR ELECTRICITY: 1980-2000

This paper was prepared by the Special Studies Branch of Energy, Mines and Resources Canada.

November, 1980.

Contents

INTRODUCTION

Forecasts of the growth rates of electrical energy consumption in Canada over the period 1980 to 2000 are presented and then translated into requirements for generating capacity beyond existing and currently committed facilities. Two sets of forecasts are presented: one based on statistical modelling techniques of the Department of Energy, Mines and Resources (EMR) and a second which represents each provincial utility's own views.

While all firms are concerned with the probable growth of the industry in which they operate and the implications of that growth for their own expansion, the concern of electrical utilities in forecasting future growth is much more critical. Within the region it serves, the electrical utility (with minor exceptions) is the industry singly responsible for meeting the growth in demand. Over or under-estimation of demand growth and capacity requirements is extremely costly. Over-estimation results in excess capacity, a non-productive use of valuable assets imposing large costs necessarily borne by the utility's customers. Under-estimation also imposes costs in the form of increased unreliability of the system, brownouts, and interruptions.

Since demand forecasts are seldom perfect, it can happen that utilities have excess or insufficient capacity. Generally, they prefer to err on the side of excess capacity for several reasons. It avoids the alternative of service interruptions; it is easier to slow down expansion than to accelerate it; and the costs of some over-investment are less than an equivalent amount of under-investment.*

Electricity demand forecasts are the basis for investment planning, and the starting point for assessing potential nuclear and other plant requirements. Long lead times (in the order of a decade or more) are required for the implementation of generation expansion plans, so it is necessary to make flexible plans now for meeting electricity demands in the 1990s. Therefore forecasts are needed for periods extending well into the future. Forecasting is particularly difficult because of long forecast periods and uncertainties about the movement of those factors which influence electricity demand - economic growth, population, price levels and rate structures, and the prices of competing energy sources. Even when there is agreement about the probable movement of these factors, there can be disagreement about their influence.

In brief, there are some significant difficulties in forecasting demand for electricity, but the effort is essential if the costs of mistaken generation and transmission planning are to be as low as possible.

There are two general perspectives from which to view demand growth - a market economics perspective and a target perspective. The target perspective involves two steps. First, one establishes an explicit social target rate of growth in electricity consumption based on judgements about the need for electricity and the economic, environmental, and social costs of generating it. Second, one develops and implements a number of measures - pricing, promotion of conservation, mandatory measures, and so on - which will ensure that these targets are achieved.

The target may be to increase consumption, or to reduce its growth below market-determined rates. One reason for establishing higher growth targets may be to accelerate the substitution of electricity for oil. Alternatively, the target may be to reduce consumption. This approach questions the value of continued expansion in electricity supplies in view of, among other considerations, the increasing costs electricity production imposes in threats to health and the natural environment, the diversion of large amounts of scarce capital from other, more socially useful alternatives, and the already high levels of electricity consumed by Canadians relative to the rest of the world.

The target approach begs some different questions. Who determines these targets and how? How can the economic and political problems of implementation be overcome? How large are the gains or losses ineconomic efficiency which such an approach might involve? These issues

---

* "Planning for Uncertainty". EPRI Journal pp.6-11, May 1978.

would require considerable examination before such an approach could be adopted. Discussion of such target-based forecasts, however, lies beyond the scope of this paper.

The forecasting techniques here are based on a market economics perspective. That is, individual consumers (firms or households) are presumed to choose the amount of electricity they want on the basis of personal preference, income, price in relation to other fuels, and a variety of other economic considerations. Utilities attempt to respond to and anticipate these market-determined demands by ensuring that adequate capacity is available to meet current and forecast load growth.

PART 1: DEMAND FORECASTING

Historical Background

From 1963 to 1974 electricity demand grew at 7.4 per cent per annum (see Table 1). This rapid growth reflected strong economic growth over the period, a declining real price of electricity, and a substantial improvement in the price competitiveness of electricity relative to oil. From 1974-78 the growth rate declined to 4.4 per cent per annum, reflecting lower economic growth rates over the period and an upward movement in the real price of electricity*. Nevertheless, electricity has continued to improve its share of the total energy market because, despite its rising price in recent years, the prices of other energy sources have risen even more rapidly.

Table 1
Summary of Recent Trends Related to Electricity Consumption

	1963-1974	1974-1978
Rate of growth of electricity consumption	7.4%	4.4%
Rate of growth of gross national product	5.6%	3.8%
Rate of growth of electricity prices*	-2.2% to -4.6%	+3.7% to +8.7%
Electricity consumption as a percentage of energy demand**	13.0% (1963)	18.0% (1978)

Source: Canada. Statistics Canada. Electric Power Statistics. Released annually. (SC-57-202)

* These figures indicate the range between the residential, commercial, and industrial sectors.

** Electricity is valued at the output equivalent of 3 412 BTU per kWh.

Electricity Growth and Capacity Requirements 1980-2000

(1) EMR Forecasts

The EMR forecasts of electricity demand growth are based on the Department's Inter-Fuel Substitution Demand (IFSD) model. The model is based on statistically estimated historical relationships between the demand for various energy sources and factors such as income and prices. Given the historical relationships, the model generates forecasts for the period 1976 to 2000 by region. The forecast growth rates vary depending upon the assumptions which are made about economic growth, the price of electricity, the price of other fuels, and a variety of variables describing population and housing stock characteristics. Thus the quality of this kind of econometric forecast depends upon four main factors:

---

* The 4.4 per cent growth rate was influenced significantly by the 1975 experience in which electrical consumption actually declined.

(1) the quality of the statistical methods;

(2) the accuracy of historical definitions of the relationships between energy demand and those factors which determine it;

(3) the realism of the assumptions made for the future behaviour of the determinants;

(4) the accurancy of the historically defined relationships between energy demand and its determinants for the prediction of future behavior.

Preliminary indications are that the EMR model performs relatively well. The forecast 1978 demand for electrical energy deviated from actual demand by less than 0.3 per cent for Canada as a whole. Deviations for some regions were slightly larger, but the difference between actual and forecast levels seldom exceeded 5 per cent.

The results of a "base-case" electrical forecast for 1980 to 2000 are set out in Table 2.

Table 2
Average Annual Rate of Growth of Electricity Consumption: 1980-2000

	EMR Forecast
Atlantic Region	2.3%
Quebec	3.8%
Ontario	2.8%
Manitoba	2.6%
Saskatchewan	3.1%
Alberta	4.1%
British Columbia	3.5%
Canada	3.3%

Source: IFSD Model Runs of Sept. 17, 1980 and Nov. 26, 1980.

This forecast reflects the following assumptions:

- real domestic product grows at 3.1 per cent per annum over the period from 1980 to 1985, 3.2 per cent fron 1985 to 1990 and 2.6 per cent from 1990 to 2000;
- the international oil price FOB is $29.27 U.S./bbl in 1980, increasing at 3.4 per cent per annum real to 1985, and 2 per cent per annum real thereafter;
- domestic oil and gas prices change from 1980 to 1990 according to pricing policies as set out in the National Energy Program (NEP);
- residential and commercial electricity prices increase at approximately 0.6 per cent per annum real from 1980 to 2000. Industrial electricity prices increase at 1.27 per cent per annum real from 1980 to 2000.

For Canada as a whole, the forecast growth rate is 3.3 per cent per annum. There is considerable regional variation around this average, ranging from a low of 2.3 per cent in the Atlantic Region to a high of 4.1 per cent in Alberta.

The forecast growth rate of electrical consumption is well below the historical average despite continuation of the trend towards a larger share for electricity in total energy consumption. The lower growth rate is attributable mainly to reduced output growth in the economy and to rising real costs of electricity production.

The growth rate of electricity consumption is the primary determinant of requirements for additional electrical generation capacity. By making assumptions about reserve requirements

and the future shape of the daily and seasonal pattern of electrical demand, it is possible to translate growth rates of electricity consumption into requirements for generation capacity. Table 3 indicates the capacity requirements for 2000 that are implicit in the base case growth forecast of 3.3 per cent.

Table 3
EMR Base-Case Electrical Capacity Requirement* Forecast
By Region for the Years 1990 and 2000
(MWe)

	1990	2000
Atlantic Region	6 453	8 002
Quebec	34 553	47 185
Ontario (East System)	26 869	35 104
Manitoba	3 818	4 851
Saskatchewan	2 732	3 854
Alberta	8 191	12 015
British Columbia	12 437	17 216
Total	95 053	128 227

* Defined as peak demand plus system reserve requirements.

Currently existing and committed capacity by region is presented in Table 4.

Table 4
Electrical Capacity Supply Available and Committed To 2000
(MWe)

	1990	2000
Atlantic Region	7 890	7 890
Quebec*	36 762	36 762
Ontario (East System)	31 165	32 046
Manitoba	4 805	5 156
Saskatchewan	2 626	2 626
Alberta	7 516	7 516
British Columbia	12 931	12 931
Total	103 695	104 927

Sources: Canada. Statistics. Electric Power Statistics. Ottawa, 1978. (SC-57-294), and Canada. Energy, Mines and Resources Canada. Electric Power in Canada 1979. Ottawa, 1980.

* Includes Churchill Falls power available on long-term contract.

The difference between existing and committed generation capacity (Table 5) and 2000 capacity requirements of the utilities (Table 4) represents the additional generation capacity required but not yet committed by the utilities. These additional capacity requirements as of 1990 and 2000 are presented in Table 5.

For Canada as a whole and for the provinces individually, it appears that, with currently committed facilities, generation capacity will be in surplus in 1990. In the period 1990-2000, additional capacity amounting to about 23 300 MWe will be required. The bulk of this expansion is in Quebec and Ontario, although that in Alberta and British Columbia is also

considerable. Together these four provinces account for over 95 per cent of the additional capacity demand. Manitoba appears not to require, even by 2000, any capacity beyond that already committed.

Table 5
Additional Capacity Required Beyond that Currently Existing or Committed
(MWe)

	1990	2000
Atlantic Region	(1 437) *	112
Quebec	(2 209)	10 423
Ontario	(4 296)	3 058
Manitoba	(987)	(305)
Saskatchewan	106	1 228
Alberta	675	4 499
British Columbia	(494)	4 285
	(8 642)	23 300

* Brackets indicate that forecast capacity requirements are less than currently existing plus committed capacity. Source: Tables 3 and 4.

For Ontario, the estimate of 3 058 MWe of additional capacity provides a rough idea of the potential nuclear expansion in the province in the 1990s. Recognizing that some of the required capacity will not be base load generation, an expansion program which was 100 per cent nuclear could support up to 4x850 MWe nuclear reactors in the 1990s. A mixed coal/nuclear expansion is more probable, and a nuclear expansion of 2x850 MWe reactors is more reasonable. These estimates are based on the 2.8 per cent electricity demand growth path forecast by the EMR model.

It is an objective of the National Energy Program that the share of oil in residential, commercial, and industrial energy consumption be no greater than 10 per cent by 1990. The fuel price adjustments included as determinants of the EMR forecast in Tables 3 and 5 will not achieve this objective, especially in Quebec, Ontario, and the Atlantic regions, where a gap is expected between the price-determined and the target share of oil consumption. The NEP's off-oil program is intended to shift the equivalent energy of this excess oil consumption into gas, electricity, or other fuels.

An assessment of relative prices, fuel availability, and other marketing factors indicates that electricity's share in this substitution program will require capacity by 1990 of approximately 3 000 MWe in Quebec, 1 200 MWe in the Atlantic and 600 MWe in Ontario* above the levels forecast in Tables 3 and 5.

This additional demand would increase Canada's growth rate of demand for electrical capacity from 3.57 per cent to 4.06 per cent per annum between 1980 and 1990.

Small variations in forecast growth rates can have a large impact on capacity requirements**, and with this in mind, the following section turns to a different set of forecasts.

---

* In the case of Ontario, since the pricing structure would achieve the target oil share between 1990 and 2000 without an off-oil program, the 600 MWe increment is mainly an acceleration of capacity requirements from the post 1990 to the pre 1990 period.

** For example, an increase in the growth rate of required capacity in Canada from 3.5 per cent to 4 per cent per annum (1980-2000) amounts to an additional requirement of about 14 000 MWe.

(2) Forecasts by Provincial Electrical Utilities

As Table 6 indicates, the provincial utilities are forecasting higher growth rates of electrical consumption than is EMR. Each utility has made its own assumptions about expected movements in those factors which will influence demand and has interpreted those factors according to its view.

The utility approach to forecasting is very different from that used by EMR. None of the existing utility forecasts rely upon econometric models, although some are in the early stages of experimentation with these models. Several make fairly extensive use of econometric methods to validate forecasts as well as to assist in the specification of price and demand relationships.

While details and sophistication of forecasting methods vary among utilities, the general utility approach to load forecasting may be described as an end-use, judgemental, and survey approach. The utilities undertake detailed analyses of historical trends in energy consumption for a large number of individual categories. They use the growth rates of these individual consumption categories to build up a picture of overall demand growth. They try to identify underlying reasons for changes in historical growth rates, and then make judgements about the influence which these factors may have on future demand.

Utilities generally analyze electrical energy demand separately for residential, commercial, and industrial consumers. In the residential sector, important factors include estimates of population growth, household formation, the mix between single and multiple dwelling units, and the likely penetration of electric space heating.

Estimating commercial demand poses some difficulty because it is a very mixed category which includes shops, offices, institutions, some light industry and, in some cases, apartment buildings. The approaches adopted include projections based on the historical relationship between commercial and residential demand, or on the relationship to commercial employment, or on the square-footage of commercial building space.

Table 6
Growth Rates of Electrical Consumption: 1980-2000

	EMR Forecast	Utility Forecasts
Atlantic Region	2.3%	4.5%
Quebec	3.8%	6.4%
Ontario	2.8%	3.4%
Manitoba	2.6%	3.4%
Saskatchewan	3.1%	3.9%
Alberta	4.1%	5.8%
British Columbia	3.5%	5.9%

The industrial sector generally receives the most detailed consideration. For the bulk customer, historical relationships between industrial output and energy demand are analyzed and future output possibilities are discussed with existing and potential customers. Based on this information, the rate of growth of bulk demand is developed. For the remainder of the industrial category the utilities often develop energy-output relationships by Standard Industrial Classification category and project electricity demand based on growth estimates for each industrial classification.

The highly detailed utility approach produces good short-term (year-to-year) forecasts of load growth. For longer-term purposes, this approach has a number of shortcomings. First, the important influence of prices on the demand for electricity and other fuels is not incorporated in any systematic way. Second, the amount of detail required involves not only collecting and analyzing large amounts of information, but also making numerous individual judgements on expected rates of growth in consumption for many individual consumption

categories. Formal, more aggregate econometric models may have the advantage of systemmatically and rigorously assessing the effect of changing price and income expectations on long-term demand.

Over the past few years the growth rates of electricity consumption have differed significantly from previous experience. The relative stability of such important factors as economic growth, energy prices, and total energy consumption no longer exists. This has reduced the adequacy of forecasting techniques which depend heavily on historical trends. Most utilities have had to revise downward their demand forecasts a number of times in recent years, and in general they are now expanding their range of forecasting tools.

The utilities' forecasts of electricity consumption, although reduced in light of recent experience, remain higher than forecasts produced by EMR. Given the differences in approach, it is not possible to specify the assumptions which account for the divergences.

The higher growth rates forecast by the utilities result in larger generation capacity requirements than those in the EMR forecasts. Table 7 compares the capacity requirements for 2000 based on the EMR forecast with those implicit in the utility forecasts.

Table 7
Capacity Requirements by Region/Province for 2000*
(MWe)

	EMR Forecast	Utility Forecasts**
Atlantic Region	8 002	10 884
Quebec	47 185	77 014
Ontario (East System)	35 104	39 603
Manitoba	4 851	6 013
Saskatchewan	3 854	4 940
Alberta	12 015	14 339
British Columbia	17 216	23 530
	128 227	176 323

* The Hydro-Quebec forecast ends in 1994. EMR extrapolated this forecast to 2000 using Hydro-Quebec's 1990-1994 growth rate.

** EMR included in the utility forecasts the same reserve margins it used in the EMR forecast. The utility load is somewhat less than the provincial load; the utility load excludes non-utility producers.

The utility forecasts imply that by 2000 additional capacity of 42 467 MWe over and above the EMR forecast will be required. Thus, while the EMR 3.3 per cent electrical growth rate assumption entails additional capacity for the 1990s of 23 300 MWe, the utility forecast implies additional capacity (i.e., beyond that already existing or committed) of 71 396 MWe.

The most significant difference between the two forecasts occurs in Quebec. The EMR base-case forecast is for 3.8 per cent electricity consumption growth in Quebec. Hydro-Quebec's forecast is 6.4 per cent*. The differential capacity requirement amounts to 30 000 MWe.

---

* If the 1978 level of consumption which industry supplies to itself were deleted from the EMR forecast, the EMR forecast growth rate of Hydro Quebec's market would be 4.2 per cent.

PART 2: SYSTEM PLANNING AND THE NUCLEAR ROLE

The previous section surveyed a range of demand estimates to 2000 and indicated the approximate range of capacity required beyond that existing and now committed. This section discusses very broadly how the system planners determine the ways in which their capacity requirements should be met.

The main objective of system planning is to meet the load forecast at a specific level of system reliability and at minimum cost.

The approach to satisfying this objective is to determine the technically feasible generation and transmission alternatives for medium and long-term system expansion and then to analyze and compare the costs and constraints of each. Costs include capital, interest, fuel, and other operating and maintenance expenses. Environmental protection measures are included at least to the extent required by law or regulatory agencies. Constraints may include the availability of finance and land, the security of fuel supply, and considerations of environment, health, and safety, and the configuration of the existing system.

An inevitable problem of system planning is the considerable degree of uncertainty about the future. The demand forecast is a particularly important source of uncertainty, since forecasts are less reliable for periods further in the future. But given the long lead times between project planning and implementation, these longer-term forecasts are critical. As well, the evolution of relative fuel costs, environmental attitudes, technical change, and the introduction of new regulations add to uncertainty. This imposes upon the utility the need for much flexibility and continual reassessment in its planning function.*

Given all these uncertainties, the following overview of the potential for nuclear generation in Canada is at best a tentative and somewhat judgemental approach, based on the evidence of the demand forecasts and some exchange of views with the various utilities which have surveyed the options in their respective areas.

REGIONAL OVERVIEW

British Columbia may develop Peace River and northern hydro sites, as well as coal-thermal generation at Hat Creek. The development of these options would satisfy demand until at least the turn of the century. Only if environmental considerations impose severe physical or economic constraints on coal and hydro generation is there any real opportunity for nuclear generation before 2000.

Alberta has plentiful reserves of very inexpensive coal, so even with more stringent and costly environmental regulation of coal, the economics of nuclear are not attractive. However, there is some concern about the amount of farm land which is used for surface-mining. Major changes in land-use policy could affect the present assessment of coal supply in Alberta.

Saskatchewan does not appear to have much scope for nuclear power because of its limited system size, and potential access to more economic energy sources from neighbouring provinces.

---

* The kind of flexibility and re-assesment implied is generally as follows: of the 10 or more years lead time needed to implement a major project, approximately 4 years consists of preliminary work and obtaining regulatory agency approvals. Near the end of this period the utility may re-assess the required timing of the project before it makes major irreversible expenditure commitments. Thus, the demand forecast is important as a guide for scheduling project preliminaries and approvals. Uncertainty about future demand suggests that utilities may enhance both security and economy by completing preliminary work and obtaining approvals ahead of need as then perceived, but carefully re-assessing the appropriate project commissioning dates.

Manitoba has a well-defined hydro development strategy, which will meet demand until at least 2000 and perhaps longer, depending on the growth rate of electrical consumption. With the completion of the Churchill River Diversion and Lake Winnipeg regulation, the marginal cost of hydro development is relatively attractive compared with coal or nuclear alternatives.

Ontario is one province in Canada for which the economics and the amounts of nuclear capacity are significant. The possibilities for Ontario were discussed in a previous section. Depending on the growth rate of electrical demand one could foresee anywhere from 2 to 7 (850 MWe) reactors beyond Darlington.

Quebec

It appears that Hydro-Quebec may be able to develop about 10 000 MWe of hydro (beyond the 10 000 MWe Phase-1 James Bay program) at a cost below that of nuclear, and a further 5 000 MWe at a cost only a little above that of nuclear. Quebec's hydro potential beyond these amounts, perhaps 10 000-20 000 MWe, would be significantly more expensive than nuclear to develop. Based on Hydro-Quebec's load forecast, it appears that its economic hydro sites will be fully developed by the mid-1990s. Depending upon government policy and public acceptability, there is a potentially important role for nuclear generation in Quebec beyond the mid 1990s.

Based on the Hydro-Quebec forecast, the utility would need about 10 000 MWe of nuclear capacity (12x850 MWe reactors) to carry it through to 2000. Government policy permitting, the utility would find it advantageous to begin this development well before 1995 so that it will have organized all of its supplies and mastered the technology ahead of the time at which dependence on nuclear capacity becomes critical.

On the EMR forecast, economic hydro is far from exhausted by 2000, suggesting less urgency in considering early implementation of the nuclear option. The EMR forecast would give the utility about another 5 years (i.e., to 2005) before the economic hydro sites are developed and nuclear plant is required. If 12 years of lead time were required for a nuclear plant commissioning and if the utility wanted, say, a 10 year learning period before dependence on nuclear capacity became critical, a decision to proceed with the expansion of the nuclear option would be needed about 1983. On the Hydro-Quebec forecast, this decision is well over-due.

Atlantic Region (N.S., N.B., P.E.I., Nfld & Labrador)

In the Maritime region (N.S., N.B., P.E.I.) there is a great deal of uncertainty concerning the future role of nuclear power. Much depends upon the relative costs of coal and nuclear, the development of acceptable institutional arrangements for sharing nuclear capacity among Nova Scotia, New Brunswick, and Prince Edward Island, as well as the evolution of public acceptability. The demand forecasts for the region indicate that the region could accommodate a second reactor in the 1990s, especially if nuclear power were to displace existing oil-fired generating capacity. Prince Edward Island could make use of nuclear power generated in other provinces. Developments in Newfoundland will be influenced significantly by decisions taken on the use of Lower Churchill Hydro power (Gull Island, 1 700 MWe or Muskrat Falls, 619 MWe). If the Island of Newfoundland were inter-connected with Labrador, the size of the expanded system could technically accomodate a nuclear plant, however if the Gull Island project were developed, the Island would not require a new plant until after 2000. If Muskrat Falls were developed, Newfoundland could opt for Gull Island hydro, coal or nuclear to meet its needs from the mid-1990s onward.

CONCLUSION

Much of Canada's economically feasible hydro potential will be fully developed before 2000. It is reasonable to foresee increasing costs and concerns associated with burning large amounts of coal. In consequence, nuclear generation could play an increasingly significant role in Canada by 2000, subject to constraints of government policy and public acceptability.

ELECTRICITY PRICING

This paper was prepared by the Special Studies Branch of the Department of Energy, Mines and Resources.

November, 1980

Contents

I INTRODUCTION

While the domestic pricing of electricity is under provincial jurisdiction, it is instructive to include the subject in discussions on nuclear energy in order to focus attention on the relationship between electricity pricing and demand and, indirectly, on the demand for the different types of generating capacity (coal, hydro, nuclear). Because it takes many years before the full structural impacts of pricing, consumption, and investment decisions work themselves out, it is essential to examine current trends in pricing with a view to long-term effects.

At a very broad level, electricity pricing may have quite different roles in energy strategy, depending on the objectives sought by that strategy. Advocates of slow growth would maintain that prices should be increased to encourage conservation, and, because of slower growth in demand, to minimize the environmental problems resulting from expanded use of coal and nuclear. The conservation objective may also produce an improvement in the allocation of resources if prices are raised to reflect the incremental cost of generating electricity from scarce resources which have alternative uses.

Alternatively, electricity pricing could be used to help achieve an objective of national self-sufficiency in oil. Increases in the price of oil are not being relied on exclusively to achieve self-sufficiency, but other means of reducing oil demand (or of increasing supply) can be found. One possibility is to keep electricity prices low in order to encourage consumers to substitute out of oil and into electricity (provided that the utility does not generate electricity using oil as a fuel).

These very broad objectives for pricing reach conflicting conclusions: a conservation objective would require higher electricity prices, while a self-sufficiency objective would suggest lower prices. The choice between objectives at this level is of course a political one and narrower objectives may dominate provincial decisions about pricing policy. For example, utilities may establish rate structures which encourage the production of electricity at the lowest possible cost. Other objectives are fairness, public acceptibility, rate stability, and the generation of revenues sufficient only to cover the cost of producing electricity. Occasionally, electricity pricing is used for slightly broader objectives such as a means of encouraging provincial industrial development.

II RATE LEVELS

Electric utilities in Canada are permitted to charge average prices which just cover depreciation based on the historical or embedded costs of their assets, fuel, and other operating costs, plus a reasonable rate of return on capital. Because generation and transmission facilities are very durable (20-30 years), and because steady inflation increases the real cost of such facilities, the cost of electricity attributable to an expansion of the utility's generation system exceeds the average price based on past accounting costs. It has thus been argued that consumers receive price signals which encourage them to use more electricity than is warranted by incremental generation costs.

The argument about over-consumption of electricity is only one result of the theory of marginal cost-pricing which, in its complete form, requires that the utility's output be valued at full marginal or incremental cost, and that electricity prices vary by time-of-use, particularly in thermal electric utilities. Time-of-use rates are discussed in the next section.

Price levels based on marginal cost may result in a large increase in revenues, depending on the extent to which users reduce their demands in response to higher prices. But the revenue requirement imposed on a utility by a province or regulatory agency is binding and most utilities are required by law to provide electricity at the lowest possible cost. Therefore, electricity price levels would not be allowed to increase to the levels that full marginal cost pricing implies--perhaps up to a doubling of current levels.

A comparison with the treatment of revenues resulting from higher oil prices is relevant. Without compensating tax measures, higher oil prices would result in large excess revenues to low-cost producers. In Canada, despite the difficulties of taxing away these excess revenues from a largely foreign-owned oil industry, there has been a movement toward a high price regime which taxes increased revenues. Electrical utilities, in contrast, are largely provincially-owned and while taxation of excess revenues would be relatively straightforward, the policies of the provincial governments, as noted, are quite different.

Higher electricity prices would reduce the rate of growth in electricity consumption and derived capacity requirements. In addition to the savings in capital costs, reduced electrical production would forestall or avoid difficult environmental and social problems: less coal would be mined and burned, less hydroelectric development would be necessary, and less uranium production and nuclear power would be needed.

There are a number of constraints preventing large increases in electricity prices. One is the obvious political difficulty which provincial governments would face in adopting an electrical pricing policy that results in much higher prices. The requirement to produce power at the lowest possible cost would probably prohibit governments from using electricity as a major source of tax revenues, regardless of the benefits in terms of other tax reductions or energy matters.

Some provinces have also used electricity pricing as an instrument of industrial development. In a few provinces, for example Nova Scotia and Newfoundland, selected industrial users have been offered subsidized power rates. In other instances, provincial policies encourage the production of low cost electricity, sometimes by pre-build and export, explicitly for the purpose of inducing industrial development. For example, Manitoba has frozen its electricity rates for five years. Quebec and British Columbia have attracted electricity-intensive industries based on low cost hydroelectric resources. However, with the competition among provinces for industry, the adoption of a low price strategy by one province creates pressure on the others to do the same.

Considerations of fairness are also a constraint on raising electricity prices sharply. Low income groups spend a much larger share of their income on electricity than do higher income groups. Uniform increases in electricity prices would therefore have a disproportionate impact on low income households. Also, most utilities have used 'declining block' rate structures in which consumers were charged a basic block rate, and were then able to buy added blocks at lower and lower prices. The lower rates in the final blocks of declining block rate structures have been used, through utility and government policy, to induce people to install electrical space heating. The fairness of increasing electrical prices for these users is a concern. Concerns about fairness are sometimes dismissed by analysts of electricity pricing, who have often suggested that fairness means prices based solely on the cost of supplying a service. They argue that utilities have been charged exclusively with meeting efficiency objectives and are not, or should not be, agents of social welfare policy.

Perhaps the major consideration in any discussion of the desirability of higher electricity prices is the implication of the use of higher prices for the achievement of provincial and national energy objectives. Canada's immediate energy problem is oil. Energy strategy is directed toward increasing the supply of domestic oil and toward reducing oil demand by increasing prices and substituting relatively abundant domestic resources such as natural gas, and perhaps coal, for oil. Higher electricity prices could drive electricity consumers into using oil and thus aggravate a problem other energy policies are trying to solve.

This issue is a difficult one. There are some clear benefits from higher electricity prices. Reduced electrical demand means lower capital requirements, and capital, like oil, is limited. Slower growth in electrical demand would help solve some of the other difficult problems in the electricity sector. The key question, though, is whether lower electrical growth reflects lower total consumption of energy, or whether it simply involves a switch to other energy sources, including oil. That question is fundamentally an empirical one and it has not yet received a conclusive answer.

Higher prices for electricity would reduce the rate of growth in demand for electricity. This in turn would reduce the need for new generating capacity of all plant types, including nuclear. For other reasons, however, electricity prices are likely to be kept low, relative to the prices for other forms of energy and to the incremental cost of generating electricity. Eventually, relatively low prices for electricity will stimulate the demand for new nuclear stations, although probably not until the nuclear industry has undergone a period of unusually slack demand, because of the current excess capacity in most electric utilities which are potential users of nuclear energy.

III RATE STRUCTURES

Historically, most electric utilities have priced their output using declining block rate structures. This pricing structure promoted the increased use of electricity and permitted electrical utilities to expand and achieve greater economies of scale, thereby lowering the average cost.

The larger electrical utilities are now beyond the stage where economies of scale can be achieved by expanding their systems. In provinces largely dependent on hydro, the cheapest sites have been developed; utilities in these provinces can expand their hydro-generated capacity only by developing more remote and usually more expensive sites (James Bay in Quebec and the Nelson River in Manitoba). In provinces which generate their electricity using coal, oil, or uranium, some savings can be achieved by moving from smaller to larger generating units. This is particularly true in the Maritime provinces, where the regional integration of energy systems would permit the installation of large, lower-cost generating units which would have too much capacity for the system of any one province. However, in most provinces, capital and fuel costs are higher now in real terms and attempts to meet the increasing demands of those concerned about environmental and health effects of electricity generation are imposing new costs on utilities. Therefore, in most provinces, increases in electrical generation will raise the average cost of producing electricity.

In response to the new cost conditions facing the industry, many electrical utilities are gradually eliminating the 'declining block' feature of their rate structures by moving toward a flat rate (the charge for each kilowatt hour remains the same regardless of the amount consumed). There is also an attempt to revise rates in a way that allocates costs among customer classes in proportion to the costs imposed on the system by each group of customers. The movement toward rates which reflect responsibility for costs imposed on the system can be justified on grounds of fairness. Such rates also ensure that changes in consumption by the different types of users alter revenues by the same amount that they alter costs.

However, the current trend to flatter rate structures falls far short of the kinds of changes which are now the subject of much discussion among economists and public interest groups. These changes would incorporate time-of-use electricity rates (the price of electricity varies both by time of day and by season) and full marginal cost pricing (basing rate levels on the cost of increases in electrical output). The latter would also imply time-of-use rates, at least in thermal electric utilities.

These electricity pricing issues received attention in Europe over a decade ago and have resulted in the reform of rates in many countries abroad. They are now the subject of much controversy in the United States where utilities are required by federal law to examine their rate-making practices in relation to the costs they face. The debate in that country has been livelier than in Canada because the proportion of electricity generated from oil in the U.S. is much higher than in this country and there has been greater public resistance to new plant construction. Many U.S. utilities have therefore already adopted peak load rates for at least their larger customers. In Canada, the public debate has been centred in Ontario where the Ontario Energy Board, after extensive hearings, has recommended fundamental changes in the pricing practices of Ontario Hydro and the municipal utilities. The public is already familiar with, and accepts, peak load pricing for other services such as telephones, airlines, and rail passenger travel.

Time-of-use or peak load rates are based on the theory of marginal cost pricing applied to products which cannot be conveniently stored, such as electricity. Peak load pricing can also be justified on the basis of a fairness objective which would price use in proportion to the costs which a given customer imposes on the electricity supply system. Full marginal cost pricing, in addition to prescribing time-of-use rates, would imply significant increases in the prices charged for electricity. Depending on how users respond to the price increase, this may result in revenues well in excess of those which the utility is allowed to collect under existing institutional arrangements. But peak load pricing may reduce the average cost of generating electricity even though the prices charged may not reflect full marginal cost. In practice, then, there is a distinction between changes in the rate structure alone (peak load or time-of-use pricing) and changes which alter both the rate structure and the average level of rates (full marginal cost pricing).

The rationale for time-of-use rates is based on the fact that electricity cannot be stored economically in most locations and in most applications. An electric utility, because it is obliged to satisfy all demands which arise, must therefore keep sufficient generating capacity on hand to meet total expected demands. These demands exhibit a broad peak during the day, sometimes with a sharper peak in the early evening, and a valley during the night and on weekends.

It follows that if it were possible to shift some demand from the peak to the off-peak period, particularly in winter when the demand is highest, substantial savings would result. First, the additional electricity produced during the off-peak period does not require additional capacity because sufficient unused capacity is already in place to meet the higher demands during the peak period. If some demand can be shifted, the utility can therefore meet all demands with a lower total installed capacity. Second, if some demand can be shifted to the off-peak period, the utility can substitute lower cost electricity produced from baseload generating plant for higher cost electricity produced from plants which operate for shorter durations. These two types of savings may result in the same amount of electricity being produced at a lower average cost.

One method of shifting demand from the peak to the off-peak period is direct load management. Under this type of arrangement, the utility contracts with the customer to curtail power during periods of high demand. The curtailment may be on a regular, daily basis or it may be required only when the system demand approaches peak capacity. Under load management contracts, the user receives a preferential rate for the supply of power which is not assured (or firm). Another is a pricing regime which encourages consumers to substitute off-peak for peak power by charging less for the former than for the latter. Depending on the price differential involved and the adjustment costs of the users, customers may be induced either to forego some consumption of electricity during the peak period, or to transfer some of this consumption to off-peak periods, namely night-time, weekends, and summer.

One factor which reduces the potential benefit to the utility from time-of-use pricing is the existence of substantial excess capacity. If peak demands do not impinge on or threaten to exceed the total capacity already installed in the utility, then there is nothing to be saved in terms of total capacity costs by reducing these demands. However, there would be fuel savings if the time pattern of demand were more uniform, since the utility could adjust the types of plants it operates without changing the mix of installed capacity. Similarly, on a daily basis, some hydroelectric utilities have sufficient seasonal storage capacity and unused turbine capacity that additional demand during the peak period does not pose additional costs on the system, since the time pattern of demand in hydro-based systems merely changes the time when the water is used to generate electricity. In both thermal and hydroelectric systems, some seasonal variation in demand is needed to permit the utility to perform maintenance on the generating plant.

Another limit to the applicability of time-of-use rates involves existing time-of-day and seasonal load profiles and the expected response of consumers to peak load prices. If daily and seasonal peak demands are not high compared to off-peak demands, then there is little to be gained by shifting peak demands to other periods. Even with some variation in demand by time-of-use, if consumers do not respond to time-differentiated prices by shifting demand from peak to off-peak periods, the utility will not be able to realize significant savings.

Users may not shift their demands to off-peak periods since the savings realized may be less than other additional costs incurred as a result of the shift, e.g., industry may have to pay premium wages for nightshifts. From a broader perspective, it is therefore necessary to consider the net social benefit resulting from time-of-use rates -- that is, the savings to the utility less the adjustment costs of the users. Time-of-use rates would also require the installation of additional metering equipment, particularly for smaller users. Given the present state of technology and the costs of manufacturing and installing meters, this is generally not economic for smaller users, but may change as the cost of metering falls.

Based on limited evidence from other countries, the response of larger industrial users to peak load rates varies markedly from industry to industry. Those industries most likely to respond to time-of-use rates use electricity intensively and have some capacity to store intermediate products over the day-time period. Examples of such industries are smelting and refining, cement, pulp and paper, and petrochemicals. Potential load shifting in the commercial sector is limited by the need to serve the public during normal business hours. In the residential sector, load shifting is possible only for selected devices which permit heat storage, such as water heaters which can be charged at night for operation during the following day, and some discretionary use of appliances, such as washers, dryers, dishwashers, etc.

For the utility, the advantage of load management as an alternative to peak load pricing is the certainty of reduction in power demand. The user, while having less freedom of choice, has the advantage of reduced charges. With peak load pricing, the utility has no absolute guarantee that users will curtail demands during the time of the system annual peak in spite of the premium price.

Utilities in many European countries have had extensive experience with peak load pricing. However, because of differences in climactic and economic conditions, industrial technologies, the availability of heat storage devices, peak/off-peak price differentials, and other factors, it is difficult to generalize the effects of time-of-use rates to load patterns of utilities in other countries. Similarly, recent limited experience in the United States has been too brief to permit definitive conclusions about long-term shifts in load patterns.

Partly because of this uncertainty, utilities in Canada have adopted a cautious approach to time-of-use rates. An additional problem is the difficulty in allocating capacity costs precisely among peak, intermediate, and off-peak loads. There are a host of different allocation methods; however, the various approaches are not universally understood, nor is there any consensus on a preferred method. These difficulties have been recognized by the Ontario Energy Board in its review of pricing and costing practices for Ontario Hydro. The board has nevertheless strongly advocated time-of-use rates for Ontario electricity customers, first for large users and then for progressively smaller users once sufficient information about cost and impact has been made available through experimentation and research. Similar recommendations were made for load management.

It is important to stress that peak load pricing and load management would tend to increase the demand for baseload plant, because shifting of peak demands to off-peak periods would allow lower cost plants which operate continuously to be installed. In turn, the least cost type of baseload plant may be coal, hydro, or nuclear, depending on regional availability and comparative cost of coal and hydro. In certain utilities, such as Ontario Hydro, nuclear has a much lower cost for producing baseload electricity than coal or hydro. Therefore, peak load pricing and load management in some provinces would tend to increase the demand for nuclear plant, although the size of the effect is uncertain, for the reasons given earlier.

IV SUMMARY

Increased prices have been proposed because existing rate levels considerably understate the cost of generating additional amounts of electricity. Consumers therefore receive price signals which result in a greater than optimal use of scarce resources used to produce electricity. The arguments against higher prices are based on concerns about political acceptability, fairness, industrial competitiveness, and energy strategy objectives. Energy

strategy is of particular concern in that higher prices, while improving the overall allocation of resources, may aggravate national oil problems. Reduced electrical demand resulting from higher prices would also depress the demand for new nuclear stations in the long run.

Electricity pricing raises issues concerned with both rate structures and rate levels. Rate structures have received the most attention, with the proposed changes involving time-of-use or peak load rates. It has been demonstrated that peak load rates will lead to cost savings in some instances, but not in others. Ontario, Quebec, and Nova Scotia are giving consideration to time-of-use rates, although the public debate has been focused in Ontario. Such changes would tend to promote the use of nuclear power.

BIBLIOGRAPHY

Cichetti, J. and Wm. J. Gillen. Evidence presented on behalf of the Attorney-General of Canada, presented before the Ontario Energy Board in the matter of Principles of Power Costing and Rate Making Appropriate for Use by Ontario Hydro. Exhibit No. 11. Toronto, May 16, 1977.

A non-technical discussion at various economic and policy issues related to marginal cost pricing.

Lim, Henry B.F. Cost-Benefit Analysis for Peak Load Pricing and Load Management. Chicago, University of Chicago, Ph.D Thesis, 1979.

A technical approach to the economics of electricity generation planning, review of quantitative effects of peak load pricing, and estimates of the saving from marginal cost pricing and load management in Nova Scotia Power.

Mitchell, Bridge M., Willard G. Manning Jr., and Jan Paul Acton. Electricity Pricing and Load Management: Foreign Experience and California Opportunities. Prepared for the California State Energy Resources Conservation and Development Commission. Santa Monica, Calif., Rand Corp., 1977. (R-2106-CERCDC)

Review of peak load rate structures and load management in Europe, estimation of effects on load shape and capacity requirements, extrapolation to California electricity demand and supply.

Morgan, M. Granger, and Sarosh N. Talukdar. "Electric Load Management: Some Technical, Economic, Regulatory and Social Issues". Institute of Electrical and Electronics Engineers Proceedings, 67:241-312, February, 1979.

A detailed review of the theory and evidence on load management and peak load pricing, description of technical issues, selective review of control and monitoring devices.

Ontario Energy Board. Report to the Minister of Energy on Principles of Electricity Costing and Pricing for Ontario Hydro., H.R.5. Toronto, Dec. 20, 1979.

Final report of the OEB on hearings concerned with electricity pricing for Ontario Hydro, emphasis on cost allocation, public policy issues.

Ontario Hydro. Electricity Costing and Pricing Study. Vol. I: Study Overview and Principal Policy Recommendations. Toronto, 1976.

Detailed discussion of conventional costing practices, demand for electricity and revenue requirements, proposed rate structures based on marginal cost.

Ontario Hydro. Electricity Costing and Pricing Study. Vol. V: Theoretical Foundations of Marginal Cost Pricing. Toronto, 1976.

Theoretical discussion of marginal cost pricing with revenue requirements, including a defense of economically efficient pricing.

A COMPARISON OF THE ECONOMICS OF NUCLEAR ENERGY AND COAL IN GENERATING ELECTRICITY

This paper is a summary of a study by the Special Studies Division of the Department of Energy, Mines and Resources.

November, 1980

Contents

Tables:

Figures:

INTRODUCTION

In planning the expansion of their systems, electrical utilities consider a variety of complex factors among which are: level and shape of the forecast load to be met; availability and cost of alternative ways of generating electricity; supply of fuel; transmission of power; land use; effects of the alternatives on people's health and safety and on the natural environment; and constraints on financing, particularly borrowing. In the end, an expansion plan emerges which incorporates a mix of different technologies designed to meet forecast load in a way which minimizes total costs, subject to the constraints imposed on the utility.

The options open to Canadian utilities vary greatly from region to region. Newfoundland, Quebec, Manitoba, and British Columbia all have economically attractive hydro potential, and Alberta and Saskatchewan have extensive coal reserves. In these provinces, both hydro power and coal offer low-cost energy options which compete with nuclear power. In Ontario and the Maritimes, large-scale, low cost hydroelectric resources have largely been exploited. Ontario lacks indigenous coal resources and must use relatively expensive coal imported from the United States or transported from western Canada. The Maritimes have indigenous coal resources, but the costs of producing them are higher than those for western Canadian deposits. In these areas, therefore, nuclear technology competes with relatively high-cost alternatives.

Of primary interest to a utility considering nuclear energy is the economic attractiveness of the CANDU system relative to other options for meeting electrical demand. In the first section the comparative economics of nuclear and coal plants are outlined. The next section discusses the base-case comparison of thermal electric generating alternatives in Ontario - a large-scale (4 x 850 MWe) nuclear station and a large-scale (4 x 750 MWe) coal-fired plant. The sensitivity of the results to several changes in assumptions about capital and operating are then tested, and lastly the results of extending analysis to different regions of the country are presented.

The analysis seeks to develop an understanding of the underlying factors which influence the economic attractiveness of the CANDU reactor on the basis of a direct comparison of plant costs, abstracting from the more detailed system considerations which determine the optimal generation mix. Ignored are the external, or social, costs of electricity production, such as the potential impacts on the natural environment and on public and occupational health and safety. These important impacts are discussed in detail elsewhere in this volume.

A NOTE ON METHODS

In assessing the comparative economics of the CANDU system, this study uses a modification of cost-benefit analysis. Data on capital costs, operating costs, and lifetime energy output are used to calculate a single supply price expressed in terms of mills per kilowatt hour. This price is the amount which would have to be charged for each unit of the project's output to recover all capital and operating costs, including a specified return on capital investment. This rate of return, which can be set at different levels, is called the "discount rate"(2).

Results are presented by setting the discount rate at two levels: 4 per cent and 10 per cent. The rate of 4 per cent is close to the real cost of capital faced by Ontario Hydro and other utilities in the market-place, i.e., the market rate adjusted for inflation. From the utility's perspective, this rate represents the cost of capital, but to society it might not adequately represent the cost of investing in electric power facilities.

Social cost-benefit analysis requires a rate of discount representing the rate of return society forgoes by investing in electrical generating capacity rather than alternate consumption or available investment opportunities. This 'social rate of discount' is the appropriate rate against which to evaluate the contribution of any investment opportunity to national economic efficiency. Unfortunately, a variety of theoretical and practical difficulties are involved in determining what actual number to attach to the social rate of discount. While no clear consensus exists, the rate generally used in the evaluation of federal government policies and projects is 10 per cent, therefore, it is used here.

NUCLEAR VERSUS COAL-FIRED GENERATION IN ONTARIO

Ontario was chosen for a base-case analysis of thermal electricity generating alternatives for several reasons. Its nuclear and coal-fired generating programs are large and mature. Because Ontario has neither significant economically attractive undeveloped hydro potential nor indigenous coal resources, further large-scale generation alternatives are confined to nuclear energy or to stations burning western Canadian or U.S. coal.

The calculations of the supply price of coal and nuclear generation are based on detailed information supplied by Ontario Hydro (8) and supplemented by personal communications with officials of the utility.

(1) The Nuclear Alternative

The reference nuclear plant was assumed to be a station of four 850 MWe units built over a 10-year period, with the first unit starting up in April 1987 and the other units following at nine-month intervals.

A detailed breakdown of capital costs in constant dollars by year expenditure and excluding interest during construction, was provided. Heavy water requirements were assumed to be 0.9 megagrams per megawatt electric at a price of $203 per kilogram* in 1978 dollars. A breakdown of capital costs is given in Table 1.

Table 1
Capital Costs of Nuclear Generating System (4 x 850 MWe)
(millions of $1978)

	Years from In-Service Date	Plant + Initial Fuel Change	Heavy Water	Total
	-7	42.9	0	42.9
	-6	109.8	0	109.8
	-5	162.2	0	162.2
	-4	243.5	0	243.5
	-3	343.3	0	343.3
	-2	391.2	0	391.2
	-1	321.0	155.5	476.5
In-Service Date of First Unit	0	193.3	155.5	348.8
	1	72.2	155.5	227.7
	2	10.1	155.5	165.6
		1889.5	622.0	2511.5

Source: Ontario Hydro (8)

Annual operating expenditures vary with the amount of electricity produced in a year; for example, fuelling costs increase in step with the amount of energy generated. Others, such as insurance or building maintenance, are more or less fixed. It was assumed that fuelling costs alone vary with the amount of energy actually produced. Annual operating costs compared to coal are summarized in Table 3.

---

* Changing supply and demand conditions in the market for heavy water may increase this cost significantly. Because heavy water costs constitute a large proportion of the capital cost of a reactor installation, further investigation of heavy water supply costs, including detailed sensitivity analysis, is needed. For this analysis, sensitivity of supply price estimates to changes in overall capital costs, as opposed to individual components, was undertaken.

Not included in those figures are the costs of commissioning, of managing irradiated fuel, and of decommissioning. The costs of commissioning are small and may be ignored without significantly affecting the results. The costs of irradiated fuel management are uncertain, but are likely to be relatively insignificant. Finally, Ontario Hydro has argued that the costs of routine decommissioning are likely to be at least offset by the salvage value of the station including the value of the heavy water inventory, so those costs may be ignored.*

(2) The Coal Alternative

The reference coal plant comprises four 750 MWe units constructed over an eight-year period with the first unit in service in April 1987 and the other units following at nine month intervals. The plant can be fuelled with bituminous coal either imported from the United States or transported from western Canada. Data on capital costs by year of expenditure are shown in Table 2.

Operation and maintenance expenses and fuelling costs are listed below. Again, only fuelling costs were assumed to vary with plant capacity. No price escalation was assumed for either coal or nuclear fuel over the project lifetime; nor was any allowance made for the costs of controlling sulphur emissions. Annual operating and fuelling costs for the coal and nuclear options are summarized in Table 3.

(3) The Results

The relative importance of capital and fuelling costs differs significantly for coal and nuclear technologies. As a result, their comparative economics depend on the average capacity factor* at which the plant operates and on the rate of return required on capital (the discount rate). Both these points are illustrated in Tables 4 and 5, which give the results of supply price calculations in terms of mills per kWh for coal and nuclear for two choices of discount rate (4 per cent and 10 per cent) and two capacity factors (80 per cent, which corresponds to base load, and 20 per cent, which corresponds to peak load). The results are summarized in Figures 1 and 2.

Because the nuclear alternative is capital intensive with low fuel costs, it tends to be economically more attractive at high average capacity factors (base or intermediate load). Coal, with low capital cost and high fuelling cost, is economically more attractive at lower capacity factors. Therefore, the choice of the lowest cost alternative depends upon the rate at which the utility plans to use the facility, and that, in turn, is determined by the characteristics of the load curve the utility must meet.

The results show that, for the base case and for each choice of discount rate and coal cost, there is a capacity factor beyond which nuclear is more economically attractive than coal-fired generation. These "break-even" average capacity factors** are a convenient way to characterize a fairly complex comparison and will be used throughout the discussion to summarize the results. While nuclear is essentially a base load technology (one intended to operate continuously at high average capacity factors), the lower the calculated break-even capacity factor the more decisive is the economic advantage of nuclear power.

As noted earlier, the choice of the rate of discount has a decisive impact on the comparative economics of coal and nuclear. The assumed discount rate and the average capacity factor are clearly very important determinants of the relative economic attractiveness of the coal and nuclear alternatives.

---

* Preliminary estimates of the costs involved have been developed and expressed in 1979 dollars (10):
  Waste management (geological disposal) - 0.3 mills/KWh
  Decommissioning a 600 MWe unit - 0.3 mills/KWh

** Average capacity factor: the number of kwh a station produces in a year expressed as a fraction of the number of kwh which would be produced if the station operated 100% of the time.

Table 2
Capital Costs of Coal-Fired
Electricity Generation(4 x 750 MWe)
(millions of $1978))

	Years from In-Service Date	Capital Cost	Percentage of Total
	-7	-	-**
	-6	-	-
	-5	28.6	2.5
	-4	92.6	8.0
	-3	130.2	11.3
	-2	202.3	17.5
	-1	281.8	24.4
In-Service Date of First Unit	0	256.5	22.2
	1	133.6	11.6
	2	28.5	2.5
		1154.1	100.0

Source: Ontario Hydro (8)

** Zero entries in the first two years are the result of assuming a common start-up date with a shorter construction period for coal-fired capacity.

Table 3
Annual Operating Expenditures
($1978)

	Operating and Maintenance	Fuelling Costs
Nuclear	34.1 million	1.7 mills/kWh
U.S. Coal	15.4 million	12.5 mills/kWh
Western Canadian Coal	15.4 million	18.6 mills/kWh

Source: Ontario Hydro, private communication.

SENSITIVITY ANALYSIS OF THE BASE CASE RESULTS

(1) Sensitivity to Changes in Capital Costs

To test the sensitivity of the base-case results to real changes in capital costs, calculations were repeated assuming that the capital costs of each facility are increased by 25 per cent in real terms, and then that the capital costs of each facility are decreased by 25 per cent in real terms. The results are summarized in Table 7. As expected, because of the relative capital intensiveness of nuclear, a proportional increase in capital costs tends to decrease the range and margin of capacity factors over which nuclear has an economic advantage.

The sensitivity of the results to a 25 per cent increase in the capital costs of nuclear relative to coal and a 25 per cent increase in the capital cost of coal relative to nuclear was also investigated. The results in terms of the impact on break-even capacity factors are summarized in Table 8.

The assumed increases in capital costs affect the comparative economics of the two systems significantly. The increase of 25 per cent in nuclear costs reduces its economic advantage to coal at any capacity factor for a given interest rate. Nevertheless, nuclear remains an attractive option for base and intermediate load given a 4 per cent rate of discount and for base load given a 10 per cent rate of discount.

(2) Sensitivity to Fuel Escalation

Two scenarios for rates of escalation in real fuel prices were investigated. The first assumes that the prices of both nuclear fuel and coal rise at a real rate of 1 per cent a year. The second assumes that coal prices increase at a rate of 2.8 per cent a year and uranium prices climb at a rate of 5.3 per cent a year*. These figures are not intended as projections of rates of growth in prices; they are used merely to investigate the direction of influence of possible rates of price increases. The impact of these rates on supply prices is summarized in Table 9.

Because the fuel costs of a coal-fired plant constitute a much larger proportion of the cost of electricity produced (see Tables 4 and 5), equal rates of increase in fuel prices increase in both cases the economic advantages of nuclear energy over coal. Even though uranium prices in the second scenario are assumed to increase twice as rapidly as coal, the effect of escalation is to narrow significantly the range of capacity factors over which coal is economically attractive.

(3) Sensitivity to Sulphur Control Costs

Two options available for controlling emissions of sulphur oxide from coal-fired stations are flue-gas desulfurization or the use of either low-sulphur coal or a mixture of low-sulphur coal and imported U.S. coal. Flue-gas desulfurization raises the capital costs of a coal-fired generating unit, increases annual operating and maintenance costs and lowers operating efficiency. The costs are indicated in Table 10.

Another option for controlling emissions of sulphur oxide calls for the burning of a fuel which is 50 per cent low-sulphur Canadian coal combined with shutting down the station in adverse weather. At current coal prices, this option, compared with one that relied totally on U.S. coal, would increase fuel costs 3.0 mills per kWh. This estimate understates the cost of sulphur control if stations are forced to shut down intermittently because of poor weather. On the other hand, it overstates the cost because some Canadian coal would be used in any case to diversify sources of fuel supply.

The costs of sulphur control by the two methods described above, along with the net present value of sulphur control costs evaluated at a 10 per cent rate of discount, are summarized in Table 11.

Given current coal prices, combustion of low-sulphur coal is economically more attractive at any plant capacity factor than flue-gas desulfurization. However, any detailed assessment of the economics of each alternative would have to allow for the possibility of changes over time in the price of low-sulphur coal.

The impact of the two sulphur-control options on the comparative economics of coal-fired stations is potentially significant. The break-even capacity factors with and without flue-gas desulfurization are summarized in Table 12. The range of capacity factors over which coal is economically attractive compared with nuclear power is greatly reduced by the costs of sulphur control.

---

* Chosen for comparability with Banerjee and Waverman (1).

Table 4
Supply Price of Thermal
Electricity Generation (Ontario)
(a 4% rate of discount is assumed)

	Capacity Factor 80% mills/kWh	% of total	Capacity Factor 20% mills/kWh	% of total
Nuclear				
Capital charge	6.5	66%	26.5	78%
Operation & maintenance	1.6	16%	5.7	17%
Fuel charge	1.7	17%	1.7	5%
Total	9.8	100%	33.9	100%
U.S. Coal				
Capital charge	3.3	20%	7.8	34%
Operation & maintenance	0.7	4%	2.9	12%
Fuel charge	12.5	76%	12.5	50%
Total	16.5	100%	23.2	100%
Western Canadian Coal				
Capital charge	3.3	15%	7.8	27%
Operation and maintenance	0.7	3%	2.9	10%
Fuel charge	18.6	82%	18.6	63%
Total	22.6	100%	29.3	100%

Table 5
Supply Price of Thermal
Electricity Generation (Ontario)
(a 10% rate of discount is assumed)

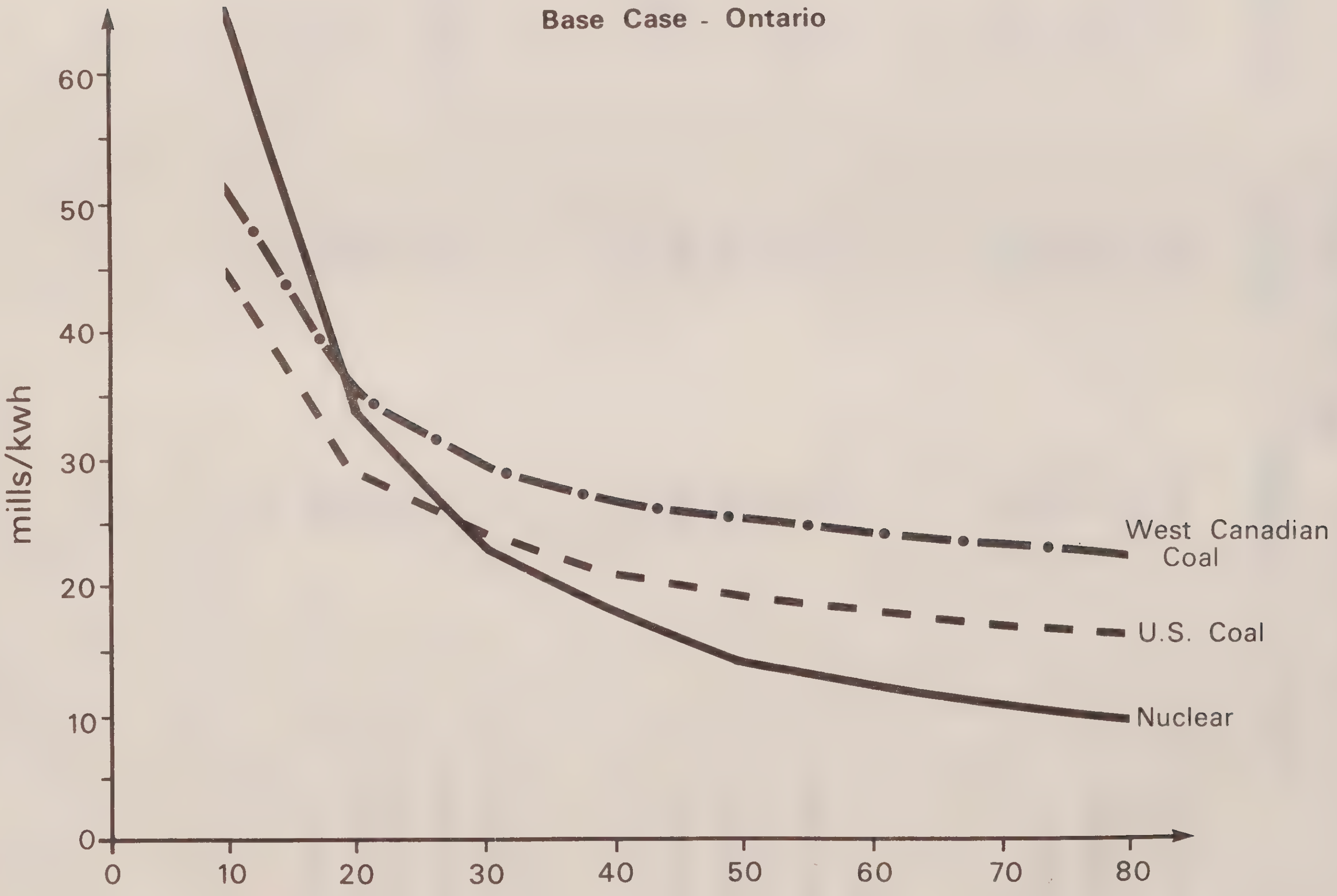
	Capacity Factor 80%		Capacity Factor 20%	
	mills/kWh	% of total	mills/kWh	% of total
Nuclear				
Capital charge	13.6	80%	55.1	82%
Operation and maintenance	1.6	10%	5.7	15%
Fuel charge	1.7	10%	1.7	3%
Total	16.9	100%	67.5	100%
U.S. Coal				
Capital charge	6.6	33%	26.1	63%
Operation and maintenance	0.7	4%	2.9	7%
Fuel charge	12.5	63%	12.5	30%
Total	19.8	100%	41.6	100%
Western Canadian Coal				
Capital charge	6.6	26%	26.2	55%
Operation and maintenance	0.7	2%	2.9	6%
Fuel charge	18.6	72%	18.6	39%
Total	26.0	100%	47.8	100%

FIGURE 1

Supply Price of Thermal Electric Generating Alternatives

($ 1978)

Base Case - Ontario



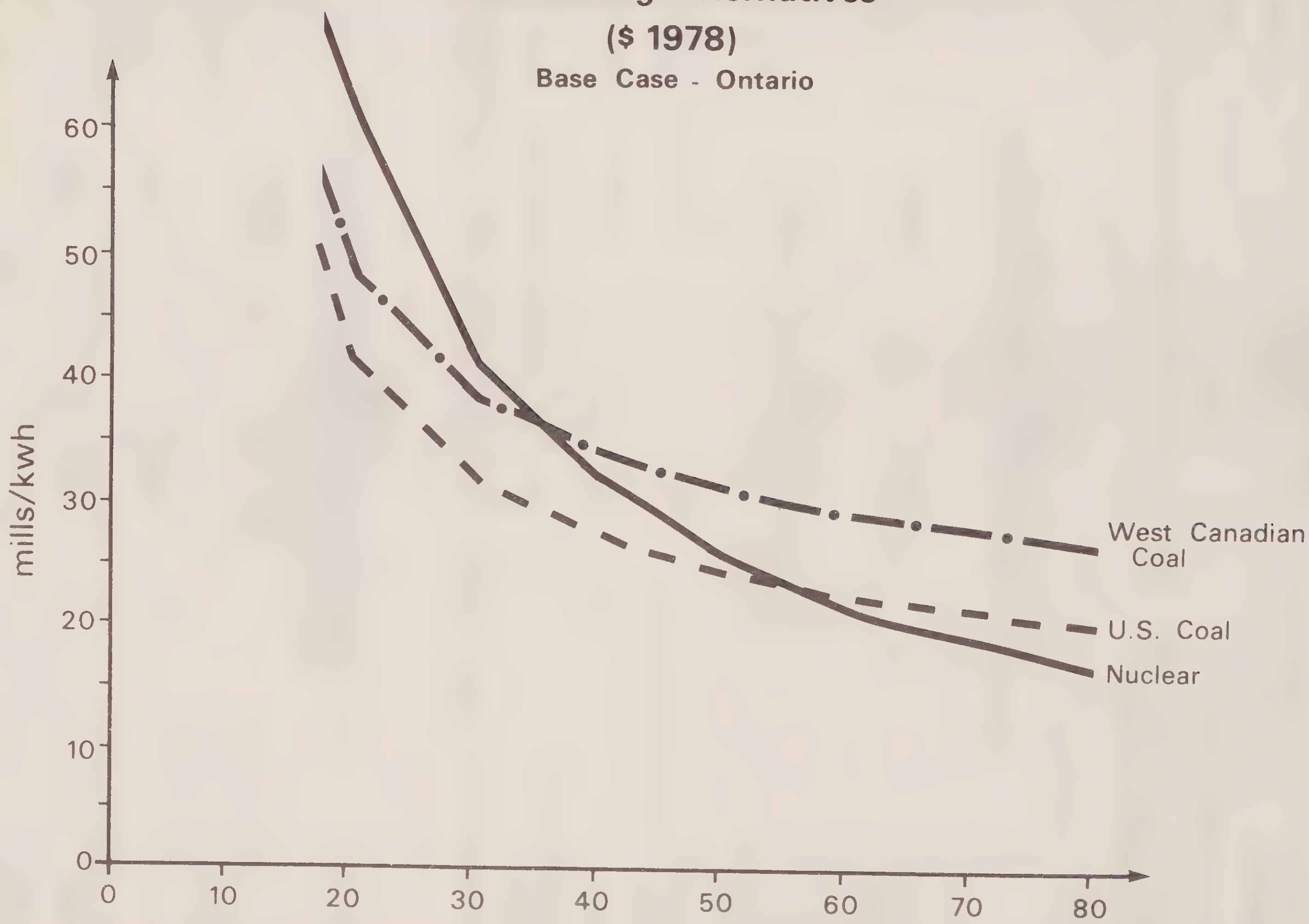
(Assumes 4% rate of discount) Average Capacity Factor (%)

FIGURE 2

Supply Price of Thermal Electric Generating Alternatives

($ 1978)

Base Case - Ontario



(Assumes 10% rate of discount)

Table 6
Break-Even Average Capacity Factors* (Base Case Ontario)

	4% Discount Rate	10% Discount Rate
U.S. Coal	30%	57%
Western Canadian Coal	19%	36%

* Capacity factor above which supply price of coal-fired electricity exceeds that of nuclear-generated power.

Table 7
Influence of Proportional* Changes in Capital Cost on Break-Even Average Capacity Factor

	Base Case	+25%	-25%
4% Discount Rate			
U.S. Coal -	30%	36%	25%
Western Canadian Coal -	19%	23%	16%
10% Discount Rate			
U.S. Coal -	57%	71%	50%
Western Canadian Coal -	36%	45%	32%

* Assumes equal proportional increase or decrease in capital costs of both facilities.

Table 8
Influence of Relative Changes in Capital Cost on Break-Even Average Capacity Factor

	Base Case	Nuclear +25 %	Coal +25%
4% Discount Rate			
U.S. Coal -	30.0%	42%	23%
Western Canadian Coal -	19.0%	26%	15%
10% Discount Rate			
U.S. Coal -	57%	84%	46%
Western Canadian Coal -	36%	53%	29%

Table 9
Influence of Fuel Escalation
on Break-Even Average Capacity Factors

		Rate of Price Increases	
	Base Case 1% COAL	1% URANIUM	5.3% URANIUM 2.8% COAL
4% Discount Rate			
U.S. Coal -	30%	29%	21%
Western Canadian Coal -	19%	14%	13%
10% Discount Rate			
U.S. Coal -	57%	51%	46%
Western Canadian Coal -	36%	31%	28%

Table 10
Costs* of Flue-Gas Desulfurization**

Capital Cost	$114/kW (1978)
Increase in operating and maintenance costs	1.38 mills/kWh (1978)
Reduction in plant efficiency	1.6%

Source: Ontario Hydro, private communication

* Based on an Ontario Hydro summary of U.S. experience.
** For flue-gas desulfurization technology which is built in, not added on.

Table 11
Costs of Sulphur Control 1000 MWe Plant* (Ontario)

	Average Capacity Factor			
	80%	60%	40%	20%
U.S. Coal with flue-gas desulfurization -mills KWh	4.3	4.8	6.2	10.6
-net present value of costs ($millions)	$435	$364	$314	$268
Mix of U.S. and Canadian coal -mills kWh	3.0	3.0	3.0	3.0
-net present value of costs ($millions)	$306	$229	$153	$ 76

* Costs and benefits discounted at a rate of 10 per cent.

Table 12
Break-Even Capacity Factors**

	Discount Rate	
	4%	10%
U.S. coal no flue-gas desulfurization	30%	57%
U.S. coal with flue-gas desulfurization	17%	34%
U.S.- Canadian coal mix	22%	42%

** Capacity factor beyond which nuclear electricity is more economical than that generated by coal-fired plants.

(4) Summary

The relative economics of the base-case coal and nuclear electricity generation can be affected by changes in both capital costs, fuel costs and environmental protection measures.

Because nuclear technology is the capital intensive alternative, its costs are more sensitive to increases in capital costs than those of the coal alternative. For this reason, even proportional rates of increase in capital costs tend to reduce the competitive position of nuclear energy.

Since coal-fired electricity generation is the fuel-intensive alternative, its costs are much more sensitive to assumed rates of increase in fuel costs over a facility's lifetime.

Capital and operating costs might be incurred in the future to improve the environmental, health, and safety impacts associated with either technology. This section focussed on one concern - the control of sulphur oxide emissions - and found that the costs of controlling such emissions greatly reduced the economic attractiveness of coal. A more complete analysis would examine the cost increases associated with other health, safety, and environmental requirements that might be imposed on either technology.

SUPPLY PRICE OF THERMAL ELECTRIC GENERATING ALTERNATIVES BY REGION

The costs of generating electricity vary greatly by region for several reasons:

i) transportation costs of coal are high relative to its energy content, and therefore the fuelling costs of an electricity generating station fired by coal increase rapidly with the plant's distance from coal deposits;

ii) the cost and availability of hydro depends on the specific site and varies greatly from region to region;

iii) a large system can take advantage of the economic savings offered by big, multi-unit stations and generally produce electricity at a cost lower than that of small systems.

This section summarizes the sensitivity of the comparative economic analysis of thermal generating alternatives to regional variations in coal prices. It is assumed, for this analysis, that large-scale thermal electric power plants built in each region under consideration are identical to those used in the base case. This assumption can be criticized because:

i) stations of the size used in the base case are too large for the foreseeable future for most utilities in Canada;

ii) the capital costs of the first nuclear station built in any province are likely to exceed the costs associated with an established nuclear program like Ontario's;

iii) the capital cost and thermal efficiency of coal- fired stations will vary according to the type of coal to be burned.

Despite these problems, the analysis does produce useful results. The diseconomies associated with using smaller units are likely to be similar for both the coal-fired and nuclear units (at least to a first approximation). Therefore, since the analysis is a comparative one, the results derived from using large units are useful. Also, the likely impact in any region of an increase in the cost of one alternative relative to another can be inferred from the sensitivity analysis described above.

(1) Results

Results are presented only for provinces which currently burn coal for thermal electric generation and for which data are available from Statistics Canada. The coal prices assumed for each region are given in Table 13. Because the energy content of uranium is so high relative to its transportation costs, fuel costs of nuclear electrical generation were assumed to be constant regardless of region. Therefore, for this analysis, the costs of nuclear electrical generation in each region are identical to the Ontario results.

The results for the break-even average capacity factor are summarized in Table 14.

Nuclear generated electricity is economically attractive in the Maritimes for both discount rates and in Manitoba at an assumed discount rate of 4 per cent (although the margin is not large). In Alberta and Saskatchewan, where thermal generating plants are located close to coal deposits, coal shows an economic advantage, and nuclear is not attractive at any capacity factor.

The results, however, must be treated with care. Given the underlying uncertainties in the data and assumptions, it is unreasonable to draw firm conclusions regarding the competitive position of nuclear energy relative to coal in many parts of Canada. It is clear, though, that with current capital and fuel costs and current environmental, health, and safety regimes, the economic advantage of nuclear energy over coal depends critically on the cost of

Table 13
Fuel Cost of Coal-Fired Electricity Generation*
($1978)

	Cost (mills/kWhe)*	Coal Type
Ontario	12.5	U.S. bituminous**
	18.6	Western Canadian bituminous**
Maritimes	12.1	Canadian bituminous
Manitoba	7.5	Lignite
Saskatchewan	3.2	Lignite and sub-bituminous
Alberta	1.8	Bituminous and sub-bituminous

* Source: Statistics Canada (14). Fuelling costs calculated using heat rates projected by Ontario Hydro for large coal-fired units.
** Source: Ontario Hydro

Table 14
Break-Even Average Capacity Factors by Region

Region	Discount Rate 4%	Discount Rate 10%
Ontario		
U.S. Coal	30%	57%
Western Canadian Coal	19%	36%
Maritimes	31%	60%
Manitoba	55%	NA
Saskatchewan	NA*	NA
Alberta	NA	NA

* Not applicable (NA). Nuclear is not economically attractive at any capacity factor.

coal. Where coal is available at relatively low prices, as in western Canada, the economic advantage of nuclear is either small or non-existent. Where coal is more expensive, as in eastern Canada, nuclear shows a clear economic advantage for base and intermediate load applications.

These conclusions are based on 1977 coal prices (12). No allowance has been made for changes in fuel prices, changes in capital costs or changes in environmental, health, and safety requirements. The direction of influence of these factors can, however, be inferred in a general way from the sensitivity analysis outlined above.

CONCLUSIONS

Electrical generation investment decisions are viewed from two perspectives: that of the utility, in which economic costs and benefits are discounted at a rate of 4 per cent (corresponding to the utility's real cost of capital); that of overall economic efficiency, in which costs and benefits are discounted at a rate of 10 per cent (corresponding to the average rate of return foregone on alternative investments).

The study indicates these conclusions for Ontario:

(1) Because nuclear is capital intensive with low fuel costs, it tends to be economically preferable at higher capacity factors. Since coal has low capital costs and high fuelling costs, it tends to be economically attractive at lower capacity factors. Thus, in the Ontario case a system expansion plan designed to minimize costs would entail a mix of coal and nuclear power.

(2) The nuclear alternative is economically attractive for base and intermediate loading in Ontario for real discount rates below about 12 per cent.

(3) Since nuclear energy is the capital intensive alternative, costs of nuclear energy are more sensitive to assumed rates of increase in capital costs and to changes in the rate of discount.

(4) Since coal is the fuel intensive alternative, its costs are particularly sensitive to assumptions regarding the rate of increase in fuel prices.

Extending the analysis on a regional basis indicates these conclusions:

(1) Where inexpensive coal (based on current prices) is available, for instance in Alberta and Saskatchewan, nuclear energy is economically unattractive at any capacity factor.

(2) Where coal is more expensive, as in the Maritimes, nuclear energy is attractive for base and intermediate load while coal remains attractive at lower load factors.

BIBLIOGRAPHY

(1) Banerjee, S., and L. Waverman. Life Cycle Costs of Coal and Nuclear Generating Stations. Prepared for the Royal Commission on Electric Power Planning. Toronto, July 1978.

(2) Bradley, P.G. The Economics of Crude Petroleum Production. Amsterdam, North Holland Publishing Company, 1967.

(3) Millward, R. Public Expenditure Economics. London, McGraw-Hill, 1971.

(4) Mooz, W.E. Cost Analysis of Light Water Reactor Power Plants. Washington, D.C., U.S. Department of Energy, June 1978. (R-2304-DOE)

(5) Morison, W.G. Economics of Nuclear Power in Canada. Conference on Nuclear Issues in the Community, Vancouver, B.C., March 6-9, 1979.

(6) National Energy Board. Canadian Electrical Utilities: Analysis of Generation and Trends, 1977. Ottawa, 1977.

(7) National Energy Board. Thermal Generating Stations: Estimated Prices at January 1977. Ottawa, 1977.

(8) Ontario Hydro. Cost Comparison of 4 x 750 MW Fossil Fueled and 4 x 850 CANDU Nuclear Generating Stations. Toronto, 1979. (Systems Planning Division, Report No. 584 SP)

(9) Ontario Hydro. System Expansion Program Reassessment Study. Final Report. Toronto, 1977.

(10) Ontario Hydro. Generation Nuclear; Submission to the Royal Commission on Electric Power Planning. Toronto, 1977.

(11) Slagorsky, C.S. Some Supply Price Estimates for Synthetic Crude Oil in Canada. Calgary, Canadian Energy Research Institute, 1978. (Working Paper 78-2)

(12) Statistics Canada. Electric Power Statistics. Volume II. Ottawa, 1979.

UNCONVENTIONAL ELECTRICITY SOURCES AND CONSERVATION

Energy, Mines and Resources Canada
Conservation and Renewable Energy Branch

November 1979

Revised January 1981

CONTENTS

Tables:

OBJECTIVE

This discussion outlines:

i) the technical and economic factors related to the production of, or substitution for, electricity by unconventional, generally renewable, sources of energy;

ii) the possible impact of conservation programs or actions on changes in electrical demand.

The time frame is the next 10-20 years.

BACKGROUND

In any discussion of nuclear policy and electricity supply, such alternatives as renewable resources and conservation have been receiving particular attention. A much better understanding of the possibilities, which would include full environmental and other external costs, development times for renewable supplies compared to the full costs and dangers of conventional technologies, and the social and institutional changes implicit, are required before their future role can be predicted.

It is clear that a broad transition away from fossil fuels, at least over the next half-century, is not seriously in doubt although the discussion of the technical and economic status of unconventional electricity supply which follows leads to the conclusion that renewables are far from ready to replace fossil fuels.

The global accumulation of atmospheric carbon dioxide, the effects of heat release on climate patterns, acid rain, and other emissions are likely to be some of the constraining factors which will dictate an eventual move toward renewable energy technologies. Whether or not nuclear power is also left behind in the renewable revolution is an open question.

This assessment of the possible contribution of renewable energy and conservation to changing electrical supply and demand is limited to the next 10-20 years. During this time there are four major changes which may occur:

i) the harnessing of renewable resources and their transformation into electric power;

ii) the use of renewable resources to supply energy in a form other than electricity, displacing conventional electrical requirements (e.g., solar water heating, solar space heating);

iii) the direct reduction of electrical demand through conservation measures;

iv) the indirect effects of conservation measures and the use of renewable energy on electrical demand.

This last category is of particular interest for policy, since other priorities, particularly the current emphasis on demand reduction to achieve self-sufficiency in oil by 1990 may result in increased electrical consumption in some sectors. For example, the penetration of electricity into the space heating market (both residential and commercial) is likely to be increased if the heating load of the buildings is reduced by improved insulation and air flow, re-design, lower temperatures, etc. With a low energy demand, capital costs are a greater proportion of total life-cycle costs, and with higher oil and gas prices, the installation of a lower capital cost electrical heating system is likely to make the most economic sense.

UNCONVENTIONAL ELECTRICAL SUPPLY

Introduction

Unconventional electrical supplies based on the transformation of renewable resources includes various technologies for conversion of solar heat and light, wind, wave, hydro and

tidal power, geothermal power, and biomass (including forest products and peat). Most of these resources are highly localized in Canada, so their potential is constrained by regional demand as well as technological factors. In addition, several suffer from wide and often unpredictable fluctuations in their availability over time so that a true systems perspective should include storage or other retiming devices or backup systems.

Frequently there are other benefits from the technology which provide additional reasons for undertaking a project; for example, river flow control, coastal breakwater, or forest waste disposal. The "package" size of a given technology may also be important in terms of its potential applicability: only certain increments in capacity will be reasonable. When looked at from the perspective of substitution for conventional supplies, certain applications such as small wind conversion machines or small hydro sites will often only be economic in off-grid locations and will be essentially a new market which does not displace central utility generation or provide for major load growth areas. Other applications such as the use of mill and forest wastes by the forest-based industries may replace in-house electricity generation from oil or gas, rather than displacing purchased electricity. If excess power is sold it may enter the grid .

Estimates of potential supply by the 1990s are informed guesses only, based on current supply price comparisons together with estimates of whether and when further R & D may reduce costs sufficiently for the technology to be cost-competitive with conventional supply. Few of the above complications are considered in the cost calculations, but supply prices for renewable sources should in any case be regarded as estimates only.

The Canadian government has taken some important steps in the past two years to establish two renewable sources with great potential: forest biomass and solar heating. A whole alphabet of programs was announced by the Minister of Energy, Mines and Resources in July of 1978: Program of Assistance to Solar Equipment Manufacturers (PASEM), Purchase and Use of Solar Heating (PUSH), Low Energy Building Design Award (LEBDA), Forest Industries Renewable Energy Program (FIRE), and Energy from Forests (ENFOR). The federal government allocated some $380 million over the succeeding 5 years to encourage the forestry industry to become more self-sufficient in energy through the use of wood residues and to set the Canadian solar heating industry on a sound technological base to satisfy the large market that is expected to develop during the next decade or two.

In the recently announced National Energy Program (NEP), further assistance was given to renewable energy. The FIRE capital grant program was expanded, with an additional $180 million, to apply to any industrial or commercial establishment making use of wood residues or other biomass fuels. The Canadian Oil Substitution Program (COSP), which will give grants of up to $800 to residential, commercial or institutional oil users who switch to other fuels, will be available to those who switch to renewable resources; also under COSP, a $1.4 billion distribution system expansion program will be made available for infrastructure associated with renewable resources as well as electricity and gas distribution (up to 10 per cent of the total allocation may go to renewables).

Economic Evaluation of Supply

In the discussion of the various forms of unconventional electrical supply which follows, approximate costs are given, and compared with those for current conventional technologies. Some general points should be noted:

i) the costs quoted for conventional electrical supply are for coal-fired conventional steam-electric plants, and for nuclear plants of the current CANDU heavy water moderated and cooled type.* A single supply price is given, in dollars (1978) per unit energy, which incorporates data on capital costs, operating costs and lifetime energy output. The supply price calculation gives, for any given interest rate, the price which must be charged against each unit of the project's output over its operating life in order to just recover lifetime capital and operating costs, and

---

* Taken from "A Comparison of the Economics of Nuclear Energy and Coal in Generating Electricity" in this volume.

earn a rate of return equal to the specified rate of interest. Based on cost-benefit analysis, the supply price thus gives the price of output which would just make a project "economic" at some given interest rate;

ii) the supply price is not the market price for electricity. All supply prices quoted here employ a 10 per cent annual real rate of discount, the rate recommended by Treasury Board for social cost-benefit analysis. Thus the supply price theoretically represents the social cost, from a national perspective, rather than the private cost to an individual firm or utility (which would generally employ a lower rate of discount). Comparisons between technologies on this supply price basis represent what is desirable in opportunity cost terms, rather than what is likely to happen based on private investment decisions;

iii) theoretically the full social cost should include all external costs such as environmental damage, health effects, etc. This has not been attempted for either conventional or renewable sources, so that differences in such external costs may well affect a judgement on comparative desirability. The extent to which such externalities are taken into account in political decisions may well affect the future contribution of various sources to satisfying energy demands;

iv) actual prices to the consumer, or costs to the utility, will depend on government policy (incentives, subsidies etc.) as well as on market forces. Hence, the reason for cost assessment on a social opportunity cost basis: government policy decisions may well be determined on the basis of narrowing the gap between private and social costs so that the former will lead to investment decisions appropriate in the social context;

v) costs are quoted for electrical production and do not include transmission and distribution costs and losses. Care must be taken in making comparisons since some renewable technologies provide electricity at the point of use, and thereby have an uncounted advantage;

vi) costs for the renewable technologies are based on the best estimate applicable today. Further R&D will alter these costs - indeed that is part of its function and measure of success. Thus in considering the potential contribution of these technologies it is more relevant to attempt to estimate whether, and when, the supply price can be brought down by further advances in basic science, technology, or production methods to approximate that of conventional electrical supply rather than to make a comparison of current costs. The potential applications discussed vary in the shape of their anticipated learning curve: this is discussed for each technology;

vii) in the light of the previous point, both because detailed cost estimates have not been made for those technologies which are not close to economic now, and because it would in fact be pointless to do so, the supply prices shown for the unconventional sources should be regarded as approximate indications only. Insufficient resources to enable anything other than 'best guesses' of costs and time-to-cost competitiveness have been devoted to these technologies in Canada so far;

viii) some of the supply prices given for renewable technologies are based on those in an earlier EMR publication (15), modified to allow for a 10 per cent social rate of return, and assuming that they represent capital costs only. This should not introduce too great an error in these cases since maintenance requirements are generally relatively small, with no fuel requirements (except possibly some minor electrical requirements for pumps etc.);

ix) greater reliance may be placed on supply prices for tidal power and solar water heating, since they are based on reasonably well developed proposals for specific applications;

x) costs are given in terms of dollars per unit of energy produced, rather than per unit of capacity, since availability is very variable.

Unconventional Energy Substitutes for Electricity

Aside from using renewable resources for electricity production, there is some potential for the substitution of other forms of energy derived from renewable resources to displace electrical demand. The most nearly economic is solar water heating; solar space heating is also discussed although the situation is more complex as this may either substitute for electricity and/or increase its consumption through use of electrical backup. Other complications concern the displacement of peak or base-load power.

Conventional Supply Prices, for Comparison

Supply prices for the production of electricity from coal and nuclear fission are shown in Table 1. These are based on a 4 x 850 MWe nuclear station constructed over a 10-year period and a 4 x 750 MWe coal station constructed over an 8-year period.* Both assume no real price escalation for fuel over the project lifetime. The 4 per cent and 10 per cent interest rates are chosen to approximate the real rate implicitly assumed by the utility (Ontario Hydro) and the social opportunity cost of capital respectively.

For base-loaded plants, operating at an average capacity factor (ACF) of 80 per cent, supply prices at a 10 per cent interest rate are 20 and 18 mills/kWh ($5.50 and $5.00 per Gigajoule) for coal-fired and nuclear generation respectively, at the busbar. For plants operating at 20 per cent of capacity, these prices are 42 and 63 mills/kWh for coal and nuclear: as expected, nuclear energy, with its high capital and low fueling cost, is less attractive for lower capacity factors.

Actual costs for electrical production will vary according to location, and the relative competitive position of conventional and renewable technologies in any given specific application and location in Canada may not be entirely captured by the comparisons given here. In particular, for comparison with renewable energy sources trapped and converted at site of use (e.g., solar home heating), transmission and delivery costs must be added to the busbar cost: this would bring the supply price for conventional electricity up to about 40 - 50 mills/kWh. (assuming 80 per cent ACF).

Solar Thermal-Electric Conversion (STEC)

Direct solar radiation is concentrated by a reflector system to obtain high temperatures at a collector, for transfer to a fluid running a turbine. One method, the so-called "power-tower", proposes the use of an elevated collector/boiler surrounded by a large array of steerable mirrors to reflect the sun's rays to the collector. Very high temperatures may be obtained at the collector: the higher this temperature (up to a point), the higher the efficiency of the turbine cycle. First generation system designs propose a pressurized water/steam turbine system, although other fluids are feasible, e.g. a closed-cycle helium turbine.

Another method is the use of distributed solar thermal electric systems which collect sunlight by separate modules and transport the energy as steam or hot water to a central location for electricity generation.

A plant with a central receiver as described is likely to be more cost-effective than methods using a number of distributed collector modules, although any form of STEC is far from economic at the present time.

Overall efficiencies of 21 per cent (10)** are anticipated for STEC. The main disadvantages of this kind of system include the high maintenance costs of the mirror field, large land area requirements, the intermittent nature of the solar radiation, requiring a storage or increased reserve capacity to back-up the solar plants, and the ability of the system to use only direct solar radiation.

---

* For further details see source quoted in Table 1.

** 65% mirror field, 80% collector/boiler, 40% turbine cycle

Table 1
Base Case Conventional Electricity
Supply Prices

	Supply Price mills/kWh (1978 dollars)			
	interest rate 10%		interest rate 4%	
	ACF 80%	ACF 20%	ACF 80%	ACF 20%
Coal Thermal Electric				
i) U.S. Bituminous Coal	19.8	41.6	16.5	23.2
ii) Western Canadian Coal	26.0	47.8	22.6	29.3
Nuclear	16.9	67.5	9.8	33.9

ACF = Average Capacity Factor

Source: A Comparison of the Economics of Nuclear Energy and Coal in Generating Electricity. Based on Ontario plants.

This latter constraint would severely reduce a plant's usefulness at more northerly latitudes and during winter, where a higher proportion of the solar radiation is diffuse. Land area requirements for ideal, southwestern U.S. locations are 1 square mile per 100 MWe capacity plant; for areas in Canada such as southern Ontario considerably more land area would be required because of the lower direct solar radiation. An experimental 10 MWe STEC unit is under construction in the California desert, and smaller ones are planned for the Mediterranean area. Solar thermal conversion for electricity generation is still at an early design stage and there is potential for considerable technological improvement; however, the economically efficient use of such plants is likely to be limited to areas of high direct solar radiation and they are unlikely ever to become economic in Canada. The present supply price for STEC in the U.S. is at least 200 mills/kWh, depending on location; of the capital costs almost 50 per cent are for the collector(s).

Small STEC systems in certain remote locations may become economically feasible; a better opportunity for use of solar thermal power may be in the provision of high temperature process heat rather than electricity.

Solar Photovoltaic Conversion

A photovoltaic cell generates power directly from light by exciting electrons and allowing them to move in only one direction. Such devices have been in use for many years to provide small power requirements for instruments in remote locations or in space satellites. For bulk power generation, single crystal silicon or cadmium sulfide/copper sulfide cells are the best candidates: research is continuing on production technologies, and on a number of other new and promising materials.

Photovoltaic technology has an inherent advantage in being free of moving parts, and thus having low maintenance requirements and a relatively long lifetime.

Progress in photovoltaics for application to bulk power generation depends on advances in basic semi-conductor physics and production methods. Present supply prices are in the neighbourhood of 1 250-1 750 mills/kWh and will have to come down by a factor of 40-60 or so to be competitive with conventional electric generation. Despite this, it is probably the only renewable energy source with the potential for a truly dramatic price change, and hopes are high that such an improvement can be achieved. Costs of $2 to $4/We (a 3-6 times improvement)

will open up markets many times larger than the original investment; and the U.S. government is putting very large sums behind its belief that costs of 50¢/W in 1986 and 20-30¢/W by the 1990s are achievable. Indications are that these targets will in fact be met, but a 100 MWe demonstration plant is unlikely before the mid-1990s. Photovoltaic conversion is unlikely to provide any significant amount of electricity in Canada in this century. However, the ability of these cells to utilize both diffuse and direct solar radiation means that they are far less constrained than many other renewable power sources in potential geographical location, and their contribution in the longer term seems assured.

Wind Energy Conversion

The extent to which wind power may contribute to Canada's energy future is uncertain, and is likely to remain so for some time. Generating electricity from the wind is constrained by two fundamental facts. First, the available power depends on the cube of the wind velocity.* For this reason wind turbine performance is highly site-sensitive, particularly for small machines, and only places with vigorous wind regimes can be regarded as suitable for exploitation. Aside from local and unassessed opportunities arising from effects from mountains, particularly in B.C., appropriate wind regimes seem to occur in regions of low population density: along the Labrador coast, around the shores of the Gulf of St. Lawrence, and on the western shore of Hudson's Bay. Southern Alberta and Saskatchewan have attractive wind regimes, but also have access to abundant supplies of conventional fuels.

The second fundamental constraint is variability. Periods of calm are periods without power. Battery storage is too expensive to contemplate for all but the most extraordinary applications. In consequence, wind turbines are suitable only for those applications with inherent storage characteristics such as water pumping for livestock, irrigation, and land drainage. Recent applications include primary power for remote sensing units, meteorological stations, and communications sites where even the cost of batteries is trivial. Larger machines have been integrated in parallel with diesel generation in remote regions.

In general, installing a small wind turbine (2 - 20 kW) with associated generator, inverter, and control circuitry together with adequate storage to meet daily needs will remain hopelessly expensive in comparison to the price charged by a utility, even if the consumer lives in a windy part of Canada. The outlook for small machines is thus not all that promising, except in off-grid situations, although traditional and hobbyist markets will justifiably attract some smaller firms.

More interesting are the possibilities offered by turbines in the 200 kW - 4 MW class if used by utilities in conjunction with pumped storage or a grid design that could take account of its uncertain nature. Such circumstances are rare, and the machines rarer, but paper studies and some experimentation indicate that the economics are not overwhelmingly unfavourable.** The vertical-axis or Darrieus wind turbine, first built by the National Research Council (NRC), has certain basic design advantages over the horizontal-axis type on which the bulk of U.S. experimentation has been focussed, especially for these high power applications. The first such experimental wind machine (230 kW) was erected in the Magdalen Islands in 1976 and represented about 1 per cent of electrical capacity. Plans are currently underway to construct a 2-4 MW vertical axis wind turbine in Quebec. Indications are that larger units of electricity may be generated cost-effectively at a small number of favourable sites. A design study (14) has recently been completed for the NRC with the objective of determining the near-optimum design configuration and size of a vertical axis wind turbine generator leading to a minimum total installed cost per unit average annual output; on-going work is investigating the integration of megawatt-scale wind generators with the grid. A recent discussion paper (12) suggests that domestic markets for large windmills will emerge in

---

* It is possible to extract twice as much power from a wind of 25.2 km/h ($25.2^3 = 16\ 000$) as it is from a wind of 20 km/h ($20^3 = 8\ 000$).

** An Ontario Hydro report indicates that while there is little prospect for economic utilization of windmills on a large scale in Ontario, they may compare favourably against base-loaded fossil fuel fired systems at selected windy sites (11).

the late 1980s/early 1990s and could amount to 500 - 5000 MW capacity by 2020. (The U.S. market penetration could range from 2 Quads* in 2000 to 6.7 Quads in 2020, much of this substituting for oil-fired generation.)

Forest Biomass

The solar energy captured by Canadian forests has been estimated to exceed total primary energy production by 2.5:1 (20 Exajoules** to 8 Exajoul^s) annually. Canada is thus almost unique in biomass resources per capita. As with heavy oils and heavy water, development of these resources cannot await the results of research elsewhere, for no other nation has the opportunity open to Canada.

Forest biomass may be used to produce or substitute for conventional energy sources in several ways: by direct combustion, to yield steam and electricity; by pyrolysis, to yield low or medium BTU gas; or by hydrogenation or fermentation to yield synthetic liquid fuels such as alcohols.

The Canadian forest industries (including pulp, paper and lumber producers, and furniture manufacturers) currently harvest and haul to the mills each year the energy equivalent of 1 EJ of wood, of which about one-third ends up as mill waste. The existence of such a large, widely distributed industry with its efficient mechanical harvesting techniques and forest management expertise leads to the identification of three scales of usage [8]:

i) the short-term would almost double the present 3.5 per cent of Canada's primary energy which is supplied by the combustion of wood. This would be done almost entirely within the present forest industry through the substitution of mill residues, bark, yard wastes, and so forth for purchased oil and gas. The aim would be the replacement of about 60 per cent of the conventional fuels now used by the forest industry over the next decade -- not a trivial goal, as that industry is presently the largest industrial consumer of petroleum products in Canada;

ii) the medium-term involves the harvest, through on-site chipping of branches, tops, and other slash now left in the for^st, as well as the harvest of non-commercial species and smaller trees in clear-cutting operations. Part of this material would be used to power the industry, and part would end up as forest industry energy export commodities -- solid fuels, electricity, perhaps methanol -- which would constitute a major long-term addition to the financial stability of the industry. Another 0.6 EJ annually would be available at this level, enough, if fully utilized, to make the forest industry a substantial net exporter of energy.

The use of such wood wastes in industry is presently cost-competitive in many situations, with supply costs of around 25 mills/kWh for electrical generation. The FIRE program of capital cost-sharing to encourage the substitution of mill and forest residues for purchased energy in the forest industry, has been established since June 1978, and along with the joint Federal-Provincial pulp and paper modernization program, should facilitate a more rapid switch. Recent changes to this program under the NEP will allow any industrial or commercial establishment making substitutions of any biomass fuels to be eligible for a grant.

It is expected that by 2000, the use of forest wastes will contribute 2 000 MW of energy production to the forest industries. Such substitutions may not have a significant direct effect on electrical consumption from the grid since most of the forest industry's use of electricity was, and will still be generated in-house. A small contribution to the grid may come from sales of surplus electricity to utilities. With the expansion of the FIRE program, the total contribution of biomass in the industrial sector as a whole may approach 10^{15} Btu per year, or about 30 000 MW of energy production. Of this, perhaps 5 - 7 per cent, or about 2 000 MW maximum, may displace purchased electricity;

---

* A Quad is equal to 10^{15} Btu (1 Btu = 1.055kJ)

** An Exajoule (EJ) is 10^{18} joules

iii) the long term exploitation of forest cellulose could form the basis of a large energy or synthetic chemical industry producing the equivalent of 2 EJs each year by harvesting areas and species presently ignored and through intensive forest management on selected lands.

In this instance the harvest and transport costs are not shared with a co-product and presently the economics are not favourable, at least against nuclear power. Highly promising early results may presently be seen in eastern Ontario, where the Ministry of Natural Resources has been working on the cloning of fast-growth broad-leaf species for a decade. No large-scale application of this concept is expected before 2000 unless a deliberate policy decision is taken to develop this electrical source in spite of its lack of cost-competitiveness with nuclear power.

Some minor use of forest biomass for electrical generation in off-grid situations, where it will principally replace diesel fuel, may occur.

Peat

The Canadian resource base for peat, last estimated in the 1930s, is poorly known, but reserves of 5×10^8 tons, equivalent to 4.5 EJs, have been identified. The total area covered in peat bogs is estimated to exceed 520 000 km^2 though only about 2 500 km^2 has been properly assayed. Ireland, Finland, and especially the Soviet Union use peat on a large scale for electricity generation and co-generation and it is possible that peat-fired generation may find a place in the supply mix of certain Canadian utilities. The federal government, Hydro-Québec and the New Brunswick Electric Power Commission are involved in feasibility studies. The use of peat has technical potential, but the economics in the Canadian situation are still very uncertain, as are the environmental implications.

Tidal Power

The tides of the Bay of Fundy have attracted power engineers for half a century; this is one of the most promising tidal sites in North America.

The present feasibility reassessment (2), based on a barrage-and-turbine concept, looks reasonably promising, with the most economically favourable sites having net capacities of 1 085 to 3 800 MWe, and costing $1.2 to $4.0 billion (June 1976 dollars). The particular operating regime chosen would give a capacity factor of about 37 per cent. Analysis of the projected capital and operating costs for the proposed Cobequid Bay facility (3 800 MW capacity, with an average annual output of 12 650 GWh, cost including transmission link of $3 988 million in 1976 dollars) indicates a supply cost of electricity of 40 mills/kWh* (1978 dollars), as compared to supply costs from conventional nuclear or coal facilities (base loaded at 80 per cent CF) of 18-20 mills per kWh.

One of the principal problems of tidal power is that supply will be based on the lunar cycle, which does not match the cycle of demand based on the normal solar day. This may dictate a need for complex methods of supply or load management, including storage or retiming.

There are still a number of uncertainties surrounding the Bay of Fundy projects. The next study phase, a prelude to engineering design, would involve detailed hydrological and silt transport modelling, assessment of environmental impacts and design of ameliorative measures, and investigatory drilling of foundation conditions. This is not all. Even the smaller version would be more than four times the size of La Rance, presently the world's largest tidal plant, which does not have Fundy's abrasive silt. A number of key environmental assumptions, especially those relating to the health of the inshore fishery, need to be rigorously tested[(5)]. Institutional and financial arrangements, yet to be studied in detail, will be critically important.

---

* Assumptions as explained previously, except that interest during construction is charged at 5.5%, as assumed by the Review Board, since it could not be separated from other capital costs.

There are concepts other than barrage-and-turbine for exploiting the tides. Moored fans or submarine waterwheels could harvest power from tidal currents, as opposed to tidal heads, and do it at lower capital cost per kW of capacity. The idea is particularly appealing forlocations like the B.C. coast, where the currents can be very powerful but without Fundy-like heads. However, only a small portion of the tidal energy could be harvested, and like windmills, site selection problems would likely limit the gross output to a small fraction of system demand.

Ocean Wave Power

Waves can be thought of as a concentrated form of wind energy. Several countries have substantial R & D programs to analyse various concepts for converting the kinetic energy from waves into electric power and determining the feasibility of various proposed wave power devices. Such devices fall into two main categories: mechanical, in which linked floating vanes or rafts rock or rotate with the waves (e.g., Salter duck); and hydraulic, such as the oscillating water column (e.g., Masuda buoy or the Russell wave rectifier).

Although obviously regional in Canada, the resource base is large and has some advantages over other renewable resources since it is relatively continuous, and is at its most powerful in the winter when energy demand is at its highest (compared with tidal or direct solar power).

However, the extraction and transmission of wave power poses formidable engineering problems and much research and development remains to be done before a commercial-size demonstration plant could be contemplated.

At present there are sufficient data to estimate the wave energy potential at only three sites off Canada's coasts (1). Some 10 kW per lineal metre of wave machine could potentially be harvested on a continuous basis, i.e., a 5-km unit in deep offshore water could meet the average power requirements of Prince Edward Island or a 200-km unit could meet over a quarter of the present requirements of British Columbia.

Realizing such potentials would require decades of work in three different areas: design and testing of wave machines of sufficient efficiency to be worthwhile, and sufficient durability to withstand a fearsomely harsh and corrosive environment; methods to moor such mechanisms off the continental shelves; and electrical (or other) power generation and transmission from a mobile device in deep water. Each is a formidable problem. The necessary technical development before large-scale commitment could take place would extend for many years and cost tens of millions of dollars, at the least. An evolutionary step could involve the dual-purpose use of machines in shallower water as generators and breakwaters combined. If a steel plant at Gabarus, N.S., is ever built, for instance, $100 million will be needed for harbour construction, much of it for a breakwater; it might be feasible to credit this money to a dual-purpose structure.

In summary, while the generation of power from ocean waves promises to be a most challenging engineering task, the potential is sufficiently attractive to be of long-term interest, although no contribution to Canadian electrical supply is likely before the turn of the century. While costs cannot be known with any precision for years to come, informed judgement puts it at something like four times the unit cost of James Bay hydro or nuclear electricity.

Ocean Thermal Gradients

The concept of using the significant temperature differences between surface and deep ocean waters is not new, having been proposed a century ago by the French scientist d'Arsonval. Only now is the concept being studied in depth, though to date none of the paper studies have been rendered into hardware. The principle is familiar: a temperature difference is used to drive a vapour cycle. In this case, the difference is only on the order of 15°C, so that the working fluid must be something normally regarded as a refrigerant, such as ammonia. Liquid ammonia, cooled by deep water, would be pumped through a vaporizer or boiler whose heat source was the surface water. The vapor would then be expanded through a turbine, from which power would be extracted, before being condensed and recycled. The

efficiency of all such processes is strictly constrained by the Carnot limit.* The machine's internal needs for power for pumping the enormous quantities of water to drive the heat transfer process are extremely high and therefore the likely system efficiency will not exceed 2 or 3 per cent (9,16).

In this context efficiency is primarily a guide to estimating the capital investment needed to produce a unit of energy. Error in estimating system efficiency is directly reflected in the capital cost per kilowatt. The small numbers and large flows make the probable error of estimate rather large, but recent U.S. work suggests that machines might be built at reasonable capital cost. Whether their performance would degrade sufficiently slowly to repay their cost is another matter.

The conventional ocean thermal gradient machine described above does not, however, appear attractive for Canadian coastal waters owing to the lack of sufficient temperature differences and to the presence, in the Gulf of St. Lawrence and the Atlantic, of substantial winter ice. One variant has been suggested, namely an air-water system exploiting the temperature difference between the ocean and Arctic air. It is conceivable that such a machine might find an application in the next century in remote Arctic locations, but since it is attempting to use water which is very near freezing as a heat source, this would require a complex system to remove ice from the necessarily large heat exchanger.

It should be pointed out that thermal dumping takes place with all fossil or nuclear generating plants: roughly two-thirds of the energy content of the fuel is rejected to air or water as waste heat. The temperature differences are typically larger than those offered by the oceans and the resource is already at or near load centres. Clearly it would be more appropriate to thoroughly exploit this wasted resource before looking to ocean thermal gradients.

Small and Low-head Hydro Developments

Hydro electricity has been the basis of electrical generation in Canada, and most of the better, lower cost, large capacity sites have been developed. While capacity remains to be exploited in B.C., Labrador and Manitoba, this will cost more, and by the end of the century little further potential for conventional hydro will remain.

Alternatives to conventional sources include low-head sources and small capacity, high-head sources - both of which may provide profound local benefits, especially as an alternative to diesel-generation in off-grid situations. The technology to develop such facilities is generally available; costs are site specific and often high, but will become more competitive with increasing oil prices.

Total potential for small hydro (under 500 kW) by the 1990s, given projected energy prices, is perhaps 1-2 GW: in many instances sites may be dual purpose (water management as well as power production) which would make the economic evaluation more favourable.

Geothermal Energy

There is a continuous slow transfer of heat from the earth's molten core to the surface, amounting on average to 0.63 W/m^2(18). This relatively trifling flux, about .5 per cent of the year-round solar energy density in southern Canada, would not be useable at all save for the remarkable energy storage capacity of the outer mantle. Geothermal energy technologies exploit reservoirs of heat which have taken hundreds or thousands of years to accumulate, and like peat, are not necessarily renewable in humanly meaningful times.

The better-known technique involves trapping naturally pressurized hot water from geyser or hot spring areas, allowing part of the water to flash into steam, and running turbines to make electricity. Well-known examples are found in northern California, Italy, and New Zealand. In Canada, most hot spring zones are remote from load centres, scattered through the

---

* The efficiency of the conversion of heat to power cannot exceed the ratio of the temperature difference divided by the absolute temperature, i.e. 15/270 or 5 per cent.

western cordillera, though exploratory drilling continues near Meager Mountain, north of Vancouver. Geothermal steam frequently has associated with it large quantities of noxious solutes, like the various compounds of sulphur, as well as other salts and sometimes heavy metals and radionuclides (17). Unless these are carefully controlled, unpleasant and occasionally dangerous surface or atmospheric pollution may occur. Current estimates of the supply cost of geothermal electricity are around 60 mills/kWh: assuming suitable sites are found in the Rocky Mountains the technology may be cost competitive by the mid 1980s.

Less well known is the use of hot water from deep sedimentary basins for space heating. Underlying large parts of the Prairie provinces and the western Arctic -- in fact, often in the places favoured with the most abundant oil and gas -- are huge volumes of water-saturated strata. While this water may occur at temperatures exceeding 300°C owing to geo-pressurization, it may also contain very large quantities of dissolved minerals: brines with 20 per cent salt content have been reported (7). Use of this subterranean heat will depend on bringing these hot brines to the surface, passing them through a heat exchanger or a heat pump and re-injecting the brine into the original stratum -- all at a cost lower than that of conventional sources. Since the temperature of these sedimentary waters is not high enough for efficient steam-raising, the primary use would be for space and water heating. An individual geothermal well pair, however, will typically cost more than $1 million, which means that the connected heat loads will have to be quite large. Commercial or possibly academic building complexes, which in terms of heat load are rather like small district heating systems, may provide useful markets in Canada. The first major demonstration site is being developed with Federal funding at the University of Regina.

Total Contribution

Table 2 summarizes the supply prices (current) and possible contribution from renewable technologies to electrical supply in Canada by about 2000. Note that the possible supplies are based almost entirely on informed guesses taking into account present and expected future price patterns, and institutional constraints, etc.

RENEWABLE ENERGY DISPLACING CONVENTIONAL ELECTRICITY

Solar Space and Water Heating

In the best known "active" solar technology, a heat-absorbing surface is exposed to the sun in a (usually flat plate) roof-top collector, and the heat is transferred by the flow of a fluid, usually water or air, over the surface.

The present life-cycle cost (to the consumer) of such systems is up to 4 times that of conventional heat sources, based to a large extent on the low and very uncertain durability of the collectors. However, with the real price of conventional fuels rising, and with manufacturers and installers gaining experience and improving designs, some systems may well be cost-effective in the relatively near future. The first market likely to be extensively penetrated is that for hot water in the domestic, commercial, or industrial sectors. In fact, a recent economic analysis (12) indicates that flat plate solar-domestic water heating is on the verge of being cost-competitive with electricity under certain assumptions and in certain areas, particularly if owner-installed. There are limited possibilities for the economic retrofitting of existing housing with solar space heating (6): the expansion of solar space heating is thus to an extent constrained by the very slow turnover of the housing stock. Furthermore, as new houses are built to take greater advantage of "passive" solar methods, e.g., better placement and sizing of windows, better insulation, weather stripping etc., and their heating requirements drop dramatically (just meeting the new proposed building code standards would reduce heating load by 38 per cent), it will become more and more difficult to justify the high capital cost of active solar heating.

In fact, although "active" solar heating may <u>substitute</u> for electricity in space conditioning, both "active" and "passive" solar techniques are also likely to <u>increase</u> its use in this area.

The supply cost (at social rate of discount) of solar hot water heating is currently around 50-100 mills per kWh (Table 2) if a 20-year collector life is assumed; 70-130 mills per kWh for a 10-year life (assuming the collector supplies 66 per cent of the annual load). It is possible that an even shorter lifetime should be used.

The total electrical consumption for hot water in the residential sector is currently about 140 x 10^{15} joules or 40 x 10^{9} kwh per year (representing a capacity of some 6 GW). Total water heating requirements are approximately double this. Thus the market potential for domestic solar water heating is very large indeed. Market penetration should be aided by the grants now available under the COSP program of the NEP.

Heat Pumps

Heat pumps utilize low-temperature environmental heat for space heating, in a reverse refrigeration concept; they can also be used in reverse for air conditioning. Heat pumps are available, and in some circumstances cost-effective now, although those currently available are not ideally designed for Canadian conditions. Widespread application should follow the development of a heat pump designed specifically for optimal operation under Canadian temperature conditions. A moderate amount of electricity or gas is needed to run the pump; in addition, since heating loads are reduced if a heat pump is part of the system, electric power or solar are most cost-effective as backup systems, so that heat pumps will likely increase the penetration of electricity into space heating. The efficiency of electric heating however is increased from 100 per cent to about 150 per cent by the use of a heat pump. Heat pumps are most logically regarded as a conservation technology, and their potential is further discussed in the following section.

THE IMPACT OF CONSERVATION ON ELECTRICAL DEMAND

Introduction

Energy conservation may be broadly defined as the most economic application of energy in a given process or activity over time. The time dimension is important because energy conservation often involves some shifting of the use of energy resources from present to future time periods - economizing on the use of energy today to make it more available tomorrow.

Energy as a resource is special because, unlike many commodities which are consumed directly, energy is valuable for the services it provides - comfortable living environments, light, convenience, transportation, etc. Demands for these energy services can be satisfied by various combinations of conventional energy resources (coal, oil, gas, nuclear), renewable energy resources (solar, wind, tidal, biomass), and by conservation technologies.

When understood in this fashion, energy conservation can be seen to provide opportunities to partially substitute for increasing the supply of energy resources. The goal of energy conservation policies and programs in general is to promote the combination of energy resources and conservation technologies which minimizes the total cost of the energy services society requires. In the simplest terms, the rule of thumb in decisions to conserve energy is that the cost involved in saving the energy be no greater than the cost of the energy that is saved. The overall purpose of this Section is to explain what the concept of least-cost energy services means and how current and planned energy conservation policies and programs can help reduce the costs of energy services.

The concept of least-cost energy services can be further extended to take a social perspective; to do so it is important to recognize that the total costs of energy services are not accurately represented by domestic prices for several reasons:

(1) domestic prices currently lie below world market prices for several energy resources;

(2) domestic prices lie below the cost of replacing oil and gas from domestic frontier or synthetic sources;

Table 2

UNCONVENTIONAL ELECTRICAL SUPPLY

Resource	Technology	Application	Current Cost a,b mills / kwn	Comment	Possible Annual Supply by about 2000 (GW)	Displacement of Conventional Electricity (GW)
Electricity-Producing Technologies						
Solar	STEC	Electricity "Power Tower"	200 up	Still in research stage, Limited application. Unlikely ever to be cost-competitive in Canada.	0	0
Solar	Photovoltaic	Electricity	1250-1750	Wide Application. Large Potential for cost reduction. Possibly cost competitive before 2000	0.01	0.01
Wind	WECS	Electricity	100-150	Limited application; off-grid situation most likely. Storage a problem.	0.1-10	0-1.0
Biomass	Combustion Co-generation	Electricity & Steam	25[d] (wood waste)	Cost-competitive and in use now for waste wood in forest industries; unlikely to be used for harvested wood except in off-grid situations. Environmental problems a constraint for peat.	2.0	?
Tidal	Fundy Barrages	Electricity	40	Lunar-cycle suply --may need retiming or storage	1.0	0.3[e]
Wave	Salter Duck, Masuda Buoy	Electricity	?	Regional application. Still in research stage	0	0
Small Hydro	-	Electricity	site-specific	Mostly off-grid application or also for water	1.2	?
Geothermal	Hot Rock Flashing	Electricity	60	Cordillera application only. Possibly cost-competitive by 1985	max. 1.0	max. 1.0
Solar	Low/Medium Temp. Convertors	Space Heat Water Heat	40-90[c] 50-100[c]	Durability and installation costs of collectors and non-technological issues are constraints	up to 0.4 0.4 - 4.0	?
Environmental	Heat Pump	Space Heat	35-60[c]	Available now.		?

Notes to Table 2

a) Current Cost - in 1978 dollars

i) Figures given for solar hot water (50-100 mills per kwh), are based on actual capital and operating costs for a flat plate liquid collector plus pre-heat tank system, providing 66 per cent of annual water heating load of 15 GJ/year, assuming a 4 person household using 57 imperial gallons per day at 120°F. Lifetime is assumed to be 20 years although this is optimistic. For a 10 year system life, range would be 70-130 mills per kwh. Low end of the range assumes owner-installed, higher end dealer-installed, costs.

ii) Figures given for tidal power are based on costs for the proposed Cobequid Bay barrage on the Bay of Fundy, a 3,800 MW facility assumed to operate at an average 38 per cent capacity (ave. annual output 12,650 GWh). For this system, interest during construction is charged at 5.5 per cent (rather than the standard 10 per cent) since these charges could not be eliminated from the total.

iii) for all other systems, costs are based on capital costs only, and should be regarded as approximate indications. For those systems still in the R&D stage and far from cost-effective, no detailed figures are available (see text). Facility lifetime is taken as 25 years for all projects, except solar space heating (5-20 year range) and heat punps (10-20 year range). A 10 per cent social rate of discount is assumed. Costs are for electrical production only, and do not cover transmission and distribution.

b) compare to conventional electrical production (for Ontario-sized plants) at a supply price of 18 mills/kwh (nuclear) or 20 mills per kwh (coal) base loaded at 80 per cent ACF; or 62 mills/kwh (nuclear) or 42 mills/kwh (coal) at 20 per cent ACF.

c) produced at site of use, should be compared to delivered conventional electricity at around 40-50 mills/kwh (base loaded), marginal social cost.

d) wood waste assumed free. Where electricity is used by co-generating industry, will not necessarily displace electricity from grid. May be sold to grid.

e) The Reassessment of Fundy Tidal Power (2) indicated that no change would occur in the nuclear (base load) expansion plans of the Maritime Integrated System in the event of tidal power availability: some reduction in fossil-fuel fired capacity would occur.

(3) the cost of environmental damages and risks to health and safety incurred in the discovery, exploitation, and delivery of energy resources and in the production and transmission of electricity are only incompletely reflected in the price consumers pay for them;

(4) the cost of ensuring that energy supplies will be secure is only incompletely reflected in prices paid for them.

In order to understand which combination of energy resource production and conservation gives the most benefits to society at the lowest cost (the 'optimal' combination), it is necessary to evaluate the choices available at these total or social costs. Since consumers of energy services tend to economize on the use of energy as energy prices rise relative to other goods and services, accounting for the full social costs of increased supply of energy services would tend to promote further conservation.

Current Federal Conservation Programs

The federal government's conservation program covers improved consumer information and awareness and more appropriate pricing levels, together with incentive programs, regulations, and an aggressive program of conservation within the federal government (both exemplary and cost-saving). Conservation programs include all fuels, although the program design to date has, of course, been guided by the overall policy priority of reduction in oil consumption. Future developments could include a greater emphasis on conservation of other energy forms, including electricity. The main conservation initiatives of the federal government* currently underway (including those now being implemented under the NEP) include:

i) a reduction in the use of conventional fuels for space heating of existing residences through the Canadian Home Insulation Program (CHIP) grants, the Home Insulation Program (HIP, in Nova Scotia and PEI), and the Super-CHIP program (PEI, Nfld., and the Territories);

ii) a demonstration of new super-efficient housing construction, comprising 1000 units to be designed and constructed across the country;

iii) a retrofit and substitution program in crown-owned buildings;

iv) working with industry on a task-force basis to develop efficiency targets and ways of meeting them;

v) assisting industrial and commercial establishments to audit their energy consumption and implement improved efficiency measures;

vi) offering grants to industrial and commercial firms in the Atlantic provinces to help finance energy conserving investments;

vii) offering grants to industrial or commercial establishments for the purchase of capital equipment to use biomass fuels;

viii) offering fast, 2 year, tax write-offs for the acquisition of qualifying equipment associated with conservation and renewable energy use;

ix) introducing legislation to enforce fuel consumption standards for new motor vehicles (currently voluntary target efficiencies exist).

Conservation programs, along with rising energy prices, are leading to a more efficient use of energy by slowly changing patterns and levels of energy consumption. This allows the Inter Fuel Substitution Demand (IFSD) Model developed by EMR for Canada to show successively lower projections of energy consumption, with no associated loss of economic performance or standard of living.

---

* A full list of the new programs is attached as Appendix I

Those conservation trends which are likely to have a significant direct impact on electrical demand include efficient building design and construction; reduced space heating and cooling loads; improved heat pump designs for Canadian conditions; improved hot water systems; lighting levels and improved lighting efficiency; improved household appliance efficiency; and general housekeeping measures aimed at more efficient applicance operation. In industry and elsewhere, there is potential for greatly improved efficiency of electric motors, and for heat recovery from and for service hot water. In addition, the use of municipal and industrial wastes for the co-generation of steam and electricity is promising, although institutional and economic constraints may limit its application.

Impact of Current and Anticipated Conservation Programs on Electrical Demand

There are numerous difficulties associated with forecasting energy demand, particularly where there is little historical data on similar economic conditions: predictions about the behaviour of consumers of energy services are thereby difficult to make with any degree of confidence. Models of the economy now being used are designed to account mainly for responses to price change and cannot adequately allow for price rigidities and structural and institutional factors - a variety of market imperfections - which greatly affect outcomes in the economy. Government policies aimed at encouraging conservation and substitution are specifically designed to help overcome these barriers and improve the efficiency of energy use in ways which benefit society the most.

Improvements in efficiency and changes in patterns and levels of energy use can be roughly estimated by technical/economic means, as they were for the first report on conservation in Canada, published in 1977 (3). However, integrating these analyses with econometric projections of demand poses enormous problems, since it is not possible to separate a purely price-related consumer response from one associated with government programs of information and incentive. Many conservation programs are designed to facilitate the response to signals already given by the market and are already reflected in demand forecasts.

This discussion should be seen in the context of the recent emphasis on fossil fuels, especially oil, in energy policy development. This emphasis has meant that conservation programs, while not limited to oil demand reduction, have been designed to concentrate on this aspect of demand, and analytical evaluation therefore has concentrated on oil supply. Impacts on electrical demand have not been assessed in detail, and, as will be seen later, when indirect influences are accounted for, some current conservation activities may in fact lead to increases in electrical demand.

It must be emphasized that work is just beginning on a comprehensive analysis of the potential for electrical energy conservation, but preliminary assessments indicate that this potential is significant even at current prices in major categories of electrical energy use. This will be discussed at a later point.

Nevertheless, from a comparison of technical and econometric demand projections, the following assessments of the impact of present conservation programs on electrical demand levels, and their relation to the IFSD model projections, have been made.

Impact by Sector

Residential Sector

The estimated impact of residential retrofit programs (CHIP, HIP, Super-CHIP) is to reduce total energy demand levels below those in the IFSD projections. The target for this program is an average 30 per cent reduction in energy use in 3/4 of the eligible (pre-1977) houses by 1987. If the target of the CHIP/HIP programs is met, as is likely now that the program has been considerably strengthened under the NEP, it is estimated that total residential energy demands will be about 25 per cent below the projection by 1990. Continued improvements in newly constructed buildings will potentially extend this reduction to approximately 35 per cent below the IFSD projection by 2000.

However, this cannot be directly translated into a 25-35 per cent reduction in electrical demand for the following reasons:

i) proportionately more electricity than other energy forms is used to supply energy for residential purposes (lights, hot water, appliances) other than space heating;

ii) insulation levels for electrically heated homes are generally closer to optimal levels so that actual energy savings from improved insulation will be less;

iii) electrically heated homes are not evenly distributed across the country; this could possibly dilute the impact of any aggregate demand reduction;

TABLE 3

AVERAGE ENERGY PRICES IN CANADA, SELECTED YEARS

Residential Sector
(1950 dollars)

	Heating Oil (per gallon)	Natural Gas (per 1000 cu. ft.)	Electric Heating (per 5000 kWh)	Motor Gasoline (per gallon)
1950	$ 0.18	$ 0.93	$ 0.57	$ 0.41
1960	$ 0.15	0.78	0.47	0.32
1970	$ 0.11	0.62	0.31	0.29
1973	$ 0.13	0.55	0.32	0.29
1976	$ 0.17	0.71	0.34	0.32
1977	$ 0.18	0.78	0.37	0.33
1978	$ 0.19	0.82	0.39	0.32
1979	$ 0.20	0.82	0.39	0.31
1980	$ 0.21	1.03*	0.40	0.32

* Estimated, preliminary

Source: EMR Energy Strategy Branch

iv) there may be indirect effects of conservation or renewable energy use which may increase electrical demand in this sector, particularly in the case of new, very energy efficient houses. In such buildings, which have relatively small heating requirements, electricity becomes more competitive with other fuels. This is essentially due to the fact that in residential units with very low space heating loads (Saskatchewan-type housing), the capital and operating costs of electrical heating systems can be significantly less than the cost of other heating

systems. Also, improvements in heat pumps, which can be considerably more efficient than electrical resistance heating, makes them even more attractive for space heating. But as heat pumps can also be used for space cooling, increased installation of heat pumps will tend to increase use of electricity for air conditioning.

Consequently, actions which significantly reduce space heating requirements are expected to increase the share of electricity in the residential heating market. Such a demand-related substitution is another example of an effect which would not be accounted for in the EMR-IFSD model.

A swing to the extensive use of electrical power for space heating will increase the winter peak demand, and may require additional load levelling measures such as storage, higher peak rates, and hybrid systems. This will alter the economics of electric space heating or back-up;

v) the nature of the interaction between the CHIP program and the new off-oil conversion grants has not been explored.

For hot water heating, lighting, and electrical appliances, the effects of improved efficiency are probably reasonably estimated in the IFSD model although there is some evidence that the Energuide appliance labelling program is beginning to have significant impact on efficiency of major appliances.

A preliminary evaluation of the load reducing and load enhancing impacts of conservation programs (CHIP and others) in this sector indicates that these may balance out, resulting in an electrical demand close to that projected in the IFSD run, even though total energy demands will be lower.

Commercial Sector

The situation here is similar to the residential sector in many respects. In existing commercial buildings, conservation potential is very significant but rental and lease conditions can markedly slow down responses to increased energy prices. New construction and operating techniques mean that most new large buildings in the commercial sector will be all-electric, with space heating dependent on the use of body heat and heat from lights, plus a backup electrical space conditioning system which includes heat storage. Demand levels will be much lower than those typical of new all-electric construction up to the mid-1970s.

Preliminary estimates again indicate that the overall effect of additional conservation measures leads to levels of electrical demand close to those projected by the IFSD model.

There is some potential for further electrical demand reductions in the residential and commercial sectors, if other specific incentive or regulatory programs were to be put in place or if research, development, and demonstration programs are particularly successful. However, these are unlikely to have a major impact by the 1990s under present conditions. This is further discussed later.

Industrial Sector

Conservation programs in this sector are aimed at expediting response to increased energy prices. Since industries' conservation efforts and their own resulting forecasts of demand levels have been incorporated into the IFSD Model, it is unlikely that additional reductions in electrical load will occur as a result of conservation programs, given the current economic and technical environment, although technical developments such as a rapid move to high efficiency electric motors may change this conclusion. Increased use of municipal and industrial wastes and co-generation, to which there are presently institutional and structural barriers, could contribute to large further reductions in electrical demand by industry. Such barriers include the suitable location of marketing sites for steam, electricity, and recovered scrap metals, financial and institutional aspects of marketing arrangements, and possible environmental and health effects.

The potential contribution of biomass, including up to 2 000 MW from mill and forest wastes, to satisfying electrical demand in the forest and other industries has been discussed earlier.

There is further potential for co-generation of electricity in industry, amounting to about 2 000 MW capacity* (in addition to the steam production, equivalent to about 44 million barrels of oil per year, which could be used for district heating or process heat). About 1 200 MW of this potential could be realized by the 1900s if an incentive program comparable to the FIRE program were available.

Municipalities with a population of 10 000 or more currently produce burnable waste with a calorific value of about 100×10^{12} BTU per year. Realizable energy potential through co-generation is probably about two-thirds of this, i.e., a total of about 12 million barrels of oil equivalent per year: about $4\ 700 \times 10^{6}$ kWh per year or 540 MW of produced electricity plus an approximately equal energy value in steam. Realistically, perhaps 200 MW of this potential will be available (in the principal cities of Canada) by the 1990s.

Further Potential for Electrical Conservation

The Least-Cost Energy Services Approach

One of the aims of conservation policy is the reduction of the total cost of energy services by exploiting conservation opportunities to the point where the cost involved in saving energy is just equal to the cost of producing more energy by the lowest cost supply alternative. This procedure - finding and adopting the optimal combination of energy resources and conservation technologies - is called 'the least-cost energy services approach'.

Recognition of the value of this approach is beginning to broaden the philosophy behind electrical planning beyond that of the traditional view (that a utility should meet a given level of demand by producing electricity at the lowest cost possible) to finding ways to provide energy services by the least expensive mix of supply alternatives, including reducing demand (conservation). In the U.S., some utilities are already implementing "capacity offset" strategies that shift their planning focus from generation to end use, where energy may be saved and required services still be provided at a lower cost than supply expansion (4). Plans such as the installation of "free" insulation in customer homes, with costs being charged to the electrical rate base, or retrofit loans, are being implemented. Utilities are thus increasingly becoming energy service industries rather than simply energy producers**.

The real costs of new conventional energy supply projects - in oil, gas, coal, and electricity - are now increasing: market prices have been rising in real terms since the energy "crisis" of late 1973, following at least 20 years of declining energy prices (see Table 3). As the price of conventional energy rises relative to that of conservation and renewable energy, it is increasingly economical to practice energy conservation and use renewable sources of energy.

---

* From calculations done by CREB.

** Although no similar initiatives have yet appeared in Canada, utilities here are beginning to show interest in the concept, and the Canadian Electrical Association has just let a contract to investigate the cost effectiveness of electrical conservation in the residential sector to see whether energy savings may be produced at a lower cost than supply expansion.

The cost of the services energy provides could be significantly reduced in Canada by the increased use of conservation technologies such as insulation, heat pumps, and control technology. The level of demand reduction that is economic for a given activity depends significantly on the prices used to evaluate the potential energy savings. For example, at domestic market prices the value of energy saved would be roughly equivalent to 25 per cent of the value of industrial output taken over the next 10 years. However, if the energy savings were evaluated at the cost of bringing on new energy supplies such as the tar sands, Artic Gas, or the Point Lepreau Nuclear Generating Station, economic savings in industry would rise to 35-40 per cent* over the same time period. Some examples of conservation technologies for the major energy sectors are presented in Tables 4, 5, and 6. Illustrative preliminary estimates of savings and costs for new and existing residences are given in Tables 7 and 8.

There are actions referred to as conservation which may be better described as conservation approaches, as distinct from the application of technologies. Conservation approaches include lowering thermostats, turning off lights, switching from autos to public transit, etc. However, these approaches are reversible in the sense that as people's preferences, perceptions, or incomes change due to changes in the economy, their habits may revert. Thus the impact of these approaches to conservation is very difficult to predict.

Accounting for the Full Social Cost

Although, as argued above, there are clearly conservation actions which are cost-effective at current market prices, these prices would in fact be higher, and still more demand reductions would make economic sense, if the market price for electricity reflected its full social cost. Social costs associated with the production of energy in general and electricity in particular come in a variety of forms, many of which, by their nature, are almost impossible to quantify. Examples of social costs of energy production include disruption of the natural environment (air, water, land), risks posed to human health, potential impacts on the earth's climate, and disruption of local communities and of the lifestyles of indigenous peoples. What these disparate impacts have in common is that, while the costs they impose on society are real and possibly large, they are not reflected in the cost of energy production and so are not reflected in the prices ultimately faced by consumers in the marketplace.

A number of attempts have been made to quantify social costs and develop mechanisms to ensure that they are fully taken into account in energy production decisions. The most well-developed of these areas is the evaluation of environmental resources. It is possible, for example, by means of public opinion surveys, or careful examination of differences in property values, to estimate the value consumers place on the natural environment. Theoretically, it is possible to imagine a set of regulatory instruments - such as a system of charges for air and water pollution - which would force business to pay the 'social cost' of environmental disruption. These costs would ultimately be passed on to energy consumers in the form of higher market prices. The problems with such an approach is that, while it is conceptually appealing, it is almost impossible to implement in practice.

What are the implications of full social cost pricing for consumers? Earlier sections of this paper have argued that in determining the least cost of providing a given energy service, producers and consumers should include conservation as the equivalent in many ways of a supply alternative. This section, then, implies that the mix of energy production and conservation technologies ultimately selected should ideally be determined by social costs, as opposed simply to the prices now faced by the consumer in the marketplace. Since prices which reflect full social costs would rise above current levels, this reasoning implies that a social cost-minimizing mix of alternatives would contain relatively more conservation and relatively less energy production.

---

* Calculations done by CREB

TABLE 4

CONSERVATION TECHNOLOGIES AND APPROACHES IN BUILDINGS

Conservation Technologies	Conservation Approaches
Insulation	Temperature levels (spaceheating and cooling, (hot water)
Air tightness	Air change levels
Heat recovery from exhaust air streams	
Lighting	Lighting levels and systems (such as task lighting)
Controls (for temperature, humidity lighting, air flows)	Maintenance procedures
	Off-peak hour operation (cleaning, working conditions)
Thermal Storage	Use of continous energy consumption indicators
Appliance technologies	
Thermography	
Heating (elements, e.g., heat pumps, furnaces, and systems - HVAC, solar)	
Cooling (elements, systems)	
Fenestration (orientation, glazing/air gaps, shutters)	
Siting	
Integrated systems, e.g., district heating and integrated appliances, covering more than on building unit or more than on aspect of energy use in a building unit.	
Technologies can provide the same level of service at lower cost (so-called "technical fix").	Approaches involve a change of service level or the type of service, but most approaches still provide direct economic benefits to consumers and firms (so-called "lifestyle-change").

TABLE 5

CONSERVATION TECHNOLOGIES AND APPROACHES IN INDUSTRY

Conservation Technologies	Conservation Approaches
Insulation - buildings, pipelines, process equipment, storage tanks	Detailed energy audits Improved maintenance (e.g. steam traps, hot water lines, lighting systems)
Waste heat recovery - heat exchange, upgrading, use	Improved operating procedures (e.g. process start-up, close-down)
Process control	Increased production rates
Combustible waste recovery and use	Scrappage rate reduction
Lighting	Work shift variations
High efficiency electric motors	
Thermal storage - often linked with waste heat recovery	
Heat pumps - often linked with waste heat recovery	
High efficiency combustion	
Low energy processes (e.g. filtration v. evaporation continous processing)	
Co-generation	

TABLE 6

TRANSPORTATION CONSERVATION TECHNOLOGIES AND APPROACHES

Automobile Technologies	Estimated Savings*	Automobile Approaches
Engine - type, performance	(10-20% savings)	Size reduction
Cooling system	(5% saving)	Performance reduction (gasoline/diesel paradox)
Transmission	(5% saving)	Improved maintenance
Better lubrication	(5% saving)	Ride-sharing (car and van pooling)
Tires	(5% saving)	Auto use reduction
Body design	(15% saving)	Driver habits
Materials for weight reduction	(5-20% saving)	Strict enforcement of speed limits
Cold-weather "package"		
Flywheel energy storage		
Truck Technologies		**Truck Approaches**
Variable fan drives	(2-6% savings)	Speed (10% saving at 55 mph compared to 65 mph)
Radial tires	(4-6% savings)	Maintenance
Aerodynamic devices	(2-6% savings)	Driver habits
Engines:		
-diesel - standard	(35% saving)	
-diesel-improved fuel economy; low engine speed, high torque	(extra 0-7% saving)	

* savings are not additive

Other Modes Technologies	Approaches
Airplanes of higher energy efficiency Rail improvements (e.g. LRC, track,controls) Urban transit improvments (e.g.weight reduction, flywheels, regenerative braking	Shift to modes of higher energy efficiency (e.g. autos to transit). Shift to telecommunitations from physical transport.

TABLE 7

ESTIMATED ENERGY USE TRENDS IN CANADIAN BUILDINGS

BUILDING TYPE	1973 "Typical"	"Measures"[a]	Energy Efficient Construction 1976-80	Future Low[b] Energy Constr: with Today's Technology
RESIDENTIAL				
(1800 sq.ft., 180 sq.m)	1000 gals/yr	600 gals/yr	250 gals/yr	100 gals/yr
Oil Cost[c] at 85¢ / gallon (18.8¢ / litre)	$ 850	$ 510	$ 213	$ 85
Extra ($'s) construction cost[e]	-	$1000	$2500	$4000
Extra investment($'s) justified to obtain savings on a basis of:[f]				
-PITE	-	1 800	3 300	4 000
-World Oil prices	-	5 000	10 000	12 000
-All-electric	-	6 000	12 000	14 400
COMMERCIAL (office buildings)	55 kWh/sq.ft per year	30 kWh/sq.ft per year	18 kWh/sq.ft per year	10 kWh/sq.ft per year
Electricity cost[d] at 30 mills/kWh	$1.75	$0. 90		$0.54
$0.30				
Extra construction Cost	Virtually zero as increased costs offset by reduced HVAC, lighting fixture, etc. costs.			

Notes:

a. "Measures for Energy Conservation in New Buildings 1978", issued by the Associate Committee on the National Building Code, National Research Council of Canada.

b. During 1980 several of these <u>residential</u> buildings will be in operation in Saskatchewan, Prince Edward Island, and Ontario; in the <u>commercial</u> sector Gulf Canada building in Calgary, Alberta, is expected to operate at 10 kWh/sq.ft.

c. Approx. residential heating oil cost at end of 1980

d. Approx. average cost of electricity, commercial sector, 1980

e. Estimates

f. At 15% interest rate, 20 year mortgage. PITE case is based on the same Principal, Interest Taxes, and Energy payments for improved residences as for typical 1973 residence in year 1 of operation; World oil price case is based on the valuation of energy savings at 1980 world oil pric~s; All-electric case is based on the valuation of electricity savings for all-electric homes at the cost of new generating facilities assuming similar generation mix requirements in each case (all preliminary estimates).

TABLE 8

LEAST COST SATISFACTION OF DEMAND FOR
20° SPACE HEATING COMFORT IN "TYPICAL"
HOME BUILT IN EASTERN CANADA IN 1973

INPUT	1973	1980	1985
Oil equivalent usage per annum (approx. G-joules)	1000 gallons (150 G-joules)	500 gallons (75 G-joules)	300 gallons (50 G-joules)
Insulation	R 10 in attic R 10 in walls R 2 in basement	R 30 in attic R 10 in walls R 12 in basement	R 40 in attic R 10 in walls R 12 in basement
Air tightness	7 air changes/hr at 50 Pascals	Improved - 5 acph at 50 Pascals	4 acph at 50 Pascals
Furnace	Standard Oil furnace	Retention head retrofit of original furnace	Condensing natural gas furnace
Temperature control	Manual	Automatic	Automatic
Retrofit costs* (total)	-	$1500	$3500
Fuel s^vings* (from 1973 base)	-	$ 400	$ 700
Fuel costs(current $'s)	$ 360	$ 400	$ 350
Other potential efficiency improvements	Total (including above) costs* $6 000 Total (including above) savings*$ 875		
Air-to-air heat exchanger (with further tightening of 2 acph at 50 Pascals)		(- 80 gallons)	
Window shutter system		(- 50 gallons)	
Improved doors		(- 20 gallons)	
"ultimate" reduction		-850 gallons (125 GJ)	

* These estimates of energy savings and costs of obtaining them can only be regarded as approximations at this point; considerable work is underway to obtain much more precise information on both the energy savings and the costs of obtaining them.

* Preliminary estimates; savings estimated at market prices (not replacement costs) in 1980's $'s.

SUMMARY AND CONCLUSION

Table 9 summarizes the contributions to electrical supply which may be expected from the renewable and unconventional sources during the 1990s. Apart from the contribution of wood waste and co-generation included in the table, only a minor impact on electrical demand can be expected from present or planned conservation programs. However, the potential for demand reduction is great. By 2000, a total additional supply of some 5-8 GW should be available, of which a very significant proportion comes from industrial co-generation and the use of wood wastes. Assuming all of this electricity were to displace conventional capacity, some 12-16 GW would be feasible. However, there are several reasons why this is unlikely to be the case.

First, some of the supply sources, particularly tidal and geothermal, are highly localized in nature, so that regional demand will to some extent constrain their application. For example, while the priority markets for a Bay of Fundy tidal power development would be those of New Brunswick, Nova Scotia, and Prince Edward Island, surplus tidal energy that may exist in the short and medium term could be transmitted to systems in the northeastern U.S.A.

Second, many applications will be appropriate only in low load-growth areas, and some, such as small-scale hydro or wind energy conversion machines, are likely to be economic only in off-grid situations and thus represent either a new market for electricity, or a substitute for small local diesel-generators. Because of the considerable costs related to transmission and distribution, small on-site facilities may become economic well before the same system would be economic for a central power station, despite economies of scale. Other applications may also create new markets for electricity, or may substitute for oil or other fuel.

A third very important reason is the problem of integration of unconventional sources through the grid: many sources fluctuate in entirely unpredictable ways (e.g., wind, small-scale solar fluctuations), while others may vary in a predictable fashion, but one which does not relate to demand cycles or tides. Thus, some form of storage or retiming is required, or load factors will of necessity be very low.

It should be remembered that the costs shown in Table 2 are supply prices, based on social opportunity costs, so that they theoretically give a national economic efficiency perspective on relative desirability. Consumer or utility decisions will be made from a different perspective, although these two decision points may be brought closer as a result of government intervention and incentive. These costs are current costs, based on the present state of development of the technology. In order to determine when such developments will become cost-effective in comparison with conventional supplies it is necessary to forecast the rate of technical progress -- which is extremely difficult. Still, it can be said fairly safely that while all the renewable technologies have some potential for cost-reduction, the only one likely to improve dramatically in economic terms is solar photovoltaic conversion. Photovoltaic supply costs are currently over 1 000 mills/kwh.

Environmental and other external costs which are not included here, associated with the different technologies, may well also influence actual decisions regarding supply sources, particularly if government intervention is applied to reduce the gap between private and full social costs.

On the basis of the current costs, the most favourable renewable technologies are solar water heating, the use of waste forest biomass, small hydro and wind in certain favourable locations, heat pumps, and tidal power. These have supply costs of the order of 25-100 mills/kWh, compared to conventional supply costs (nuclear and coal) of 18-20 mills/kWh base loaded, 42-62 mills/kWh at 0.2 capacity factor, at the busbar (Table 1).

It is unlikely that present conservation programs, which were developed in a climate of concern about oil costs and supplies, will make a major impact on electrical demand. However there does exist considerable potential for the cost-effective reduction of electrical demand, even based on current market prices for electrical power, and work in this area is now getting underway. Some utilities in the U.S.A. are already beginning to take the "least cost energy services" approach and shift their planning focus from simple power generation to satisfying end use requirements.

TABLE 9

SUMMARY OF POSSIBLE CONTRIBUTION OF UNCONVENTIONAL SUPPLY TO ELECTRICAL SUPPLY/DEMAND BALANCES, 1990 AND 2000

Electrical Supply or Displacement per year, 1990 - 2000

	10^{12}Btu	10^{6}kWh	MW Production*
Photovoltaic	0.3	88	10
Wind	3	880	0-1 000
Tidal	9-30	2 600-8 800	300-1 000
Small Hydro	30-60	8 800-17 520	1 000-2 000
Geothermal	max. 30	max. 8 800	max. 1 000
Biomass	60	17 520	2 000
Other Industrial Co-generation	36	10 512	1 200
Municipal Co-generation	6	1 750	200
TOTAL	115-165	33 350-48 350	4 710-8 410

* Note this is not equivalent to displaced capacity.

Furthermore, there remains the issue of whether electrical supply is appropriately priced, and whether, if full social costs were taken into account, still more electrical demand reduction measures would make economic sense. Further government programs to encourage conservation of electricity might be warranted if these costs cannot be appropriately quantified and reflected in the market price.

APPENDIX 1

NEP: NEW FEDERAL INITIATIVES IN CONSERVATION & RENEWABLE ENERGY

I FEDERAL CONTACTS

1. Federal Contacts - Conservation & Renewable Energy
2. Conservation and Renewable Energy Branch

II CONSERVATION & RENEWABLE ENERGY PROGRAM

1. The Canadian Conservation and Renewable Energy Program

III BUILDINGS

1. Canadian Home Insulation Program (CHIP)

With the announcement of the National Energy Program, October 28, 1980, Energy, Mines and Resources, Conservation and Renewable Energy Branch has now assumed policy and program responsibility for CHIP. The transfer date for financial matters will be April 1, 1981. Through a contractual agreement; CMHC will continue to process CHIP applications and issue the cheques to householders.

A CHIP Administration unit has been established within the Buildings and Urban Energy Division of the Conservation and Renewable Energy Branch to undertake the following functions:

a) Program monitoring and evaluation including a major evaluation of CHIP to be completed by the end of 1981.

b) Improving the quality and quantity of consumer advice on home insulation, including establishing better linkages with Ener$ave, and developing appropriate training, consumer information and protection mechanisms.

c) Coordination of technical research and development related to insulation including resolving technical problems; liaising with industry and certification and standards agencies.

By April 1, 1981 funds will be available in the CHIP budget for the testing and demonstration of insulation techniques to further improve housing energy savings; and for the development of federal/provincial agreements in support of appropriate consumer protection activities and consumer information and advice. A breakdown of the proposed CHIP budget for 1981-82 is as follows:

CHIP	1981-82 ($ millions)
Operating (EMR)	
a) Administration	1.0
b) Program Analysis and Technical Support	4.0
Contributions	
a) Grants to individuals	237.0
b) CMHC administration	12.5
c) Federal/Provincial agreements	10.5
Total	$265.0

2. Super Retrofit Program

In provinces and territories where neither natural gas nor reasonably priced electricity is available as an alternative to oil (Newfoundland, Prince Edward Island, the Yukon, and the Northwest Territories), the oil substitution grant may be applied both

to provide assistance for conversion expenditures to wood, propane, and other available non-oil sources, and in addition, to fund a super retrofit program which will include measures such as Energy Audit, Oil Furnace Retrofits, and additional insulation. Under the program, grants will be available up to a maximum of $800 covering 50% of the eligible costs. Grants provided to householders under this program are in addition to those provided under the CHIP and HIP programs.

Details of the program are being developed in consultation with affected provincial and territorial governments. The program will be delivered by the Federal Government through federal offices in each province and territory.

3. Arctic Housing Standards

This program will be directed to the development of energy conservation standards for arctic housing taking into account climatic conditions, energy supplies and costs, and future housing requirements. The standards will be developed in conjunction with the territories, Quebec, and Newfoundland and Labrador during the current and next fiscal year, and when developed will be applied to all federally funded and insured housing units constructed in the territories and northern parts of the appropriate provinces.

A committee will be established involving representatives of the various provinces and territories as well as EMR, DINA, DPW and CMHC. This committee will develop detailed terms of reference for analysis to be conducted by consultants of possible standards or elements to be included in the housing standards. The committee will also review the recommendations to produce and coordinate the final standard.

4. Super Energy Efficient Housing Demonstration

This program will provide a total of $6 million dollars to construct approximately 1000 super energy efficient housing units across the country over a three year period (FY 1981-82 to 1983-84). Details of the program will be developed in cooperation with provincial governments and representatives of the home building industry.

The objective of the Housing Demonstrations is to involve house builders in constructing housing units which are similar to those constructed under the Saskatoon Demonstration and it is hoped that a total energy budget of 100 kwt hours per square meter per year will be adhered to for all units constructed under this program. In principle, those participating in the program will be limited to builders who normally construct a significant number of housing units each year (minimum of 20). Further, it is expected that the units constructed under the program will be built in clusters of approximately 20 units in order to gain maximum publicity from the demonstrations. It is hoped that as many builders as possible will be able to participate in this program so that different approaches might be explored by different builders and that the different experiences might be shared by all who participate in the program and all who are exposed to the program as a result.

Funding available under the program (average $6000 per house) must be used to assist in the design and evaluation of houses to be constructed in the demonstration projects for training builders and tradesmen on the appropriate techniques and care involved in construction, for site supervision during the construction process, for making the houses accessible to the public as demonstration units after construction is completed, for maintaining a documented record of the construction process, for publicizing and promoting the demonstration and the techniques used in the various houses, and for keeping records of the energy performance of the houses once they are occupied. It is not expected that money will be used to fund the increased construction costs of the housing units.

The program will begin by a process of detailed discussions with provincial/territorial governments and building associations, to secure full cooperation and sign formal agreements specifying the objectives and procedures to be followed in implementing the program. It is hoped that these agreements can be completed in the balance of this fiscal year and that approximately half of the housing units will be constructed during the summer of 1981.

5. District Heating Detailed Engineering Design

Funding up to a maximum of $1 million will be provided to conduct detailed engineering designs of sites lending themselves to the implementation of district systems in the Atlantic Region.

District heating (DH) is the provision of hot water from a central boiler or a source of waste heat to heat family housing units or commercial buildings. DH is widely used in Europe but is considering a new technology in Canada, about which very little is known. Large furnaces burning gas or oil can heat the water required for a DH system much more efficiently than can smaller furnaces, but the most promising potential for savings lies in the ability of a DH system to utilize waste heat. A DH system can be considered a "market" for the significant amounts of heat presently being wasted by electrical generating stations (which traditionally waste 2/3 of the energy used) or the reject heat from industrial processors such as pulp and paper mills, or the heat which can be produced from burning municipal wastes.

Canada has virtually no experience with community energy systems, and the absence of a well-documented demonstration of DH prevents municipalities or utilities from introducing systems of this nature, largely because the design costs to establish viability are high and involve considerable risk.

Preliminary studies have been conducted in the Atlantic Region which indicate that a number of sites probably would lend themselves to the implemetation of DH systems, particularly Halifax and Charlottetown which could utilize either waste heat or alternate fuels such as municipal solid waste, or both in combination. Both sites would back out imported oil.

These preliminary assessments indicate the need for in-depth evaluation and detailed engineering design to establish cost and viability, and to develop the required institutional arrangements, a comprehensive implementation strategy, and a plan for monitoring and information dissemination.

Study costs will be fully funded by the Federal Government although direction and study design will include federal, provincial, and local input.

An essential component of the studies required under this program will involve in-depth analysis of study results and evaluation of methodologies used with a view to establishing validity of findings and suitability of the DH project as a long-term public or private investment.

6. Municipal Energy Management Program

This program addresses the energy challenge facing Canadian communities by proposing financial assistance to permit municipalities to hire full-time energy managers.

Some $20 million has been ear-marked for this program which combines job creation with energy conservation. It is proposed to pay the first-year salaries of some 900 municipal energy managers contingent upon agreement by the municipalities to continue funding for at least one additional year.

The program is expected to realize significant energy savings in three distinct areas:

1. Internal Energy Management

   This concerns the management of energy used directly by municipalities themselves and involves: conducting energy audits to identify the patterns of energy consumption in municipal buildings, vehicle fleets, street lighting, water and sewage treatment and other operations; identifying areas of potential savings; and developing programs of energy management and retrofit.

2. Review of Services, By-Laws and Municipal Planning

Beyond the direct use of energy by a municipal government, many services and regulations within the municipal jurisdiction affect energy consumption: zoning regulations; traffic flows; building codes; public transit; sub-division planning; garbage collections or re-cycling. Analysis of relevant regulations with a view to modification can yield substantial energy savings.

3. Community Involvement/Outreach

Many energy conservation activities are not subject to direct control or regulation by municipalities but can be undertaken by community organizations. Municipal energy managers will be able to provide guidance and support services to these groups in order to promote conservation acitivites in areas such as: re-cycling; insulation clinics; home energy audits; car pooling; and the dissemination of conservation information.

Provision has been made for funding appropriate training programs as municipal energy managers are hired, and providing technical information including an exchange of case studies between municipalities.

The program will continue until 1985.

7. Low Cost Energy Conservation Initiatives

Buildings:

Commercial Sector Task Force Development; Workshops; seminars, studies aimed at improving awareness of energy conservation opportunities in the commercial sector; studies and pilot programs, for example, in the areas of domestic water heating and consumer reactions to energy conservation initiatives in the residential and urban sectors.

8. Arctic Community Demonstration

This program will develop and finance a demonstration of enhanced conservation and renewable energy systems in a selected arctic community with the intention of reducing as far as economically justifiable the reliance of that community on oil. Items to be demonstrated in the community include conservation technologies in the communities' buildings and industries, wind energy, photovoltaics and other solar technologies, co-generation, and the recovery of energy from thermal and material wastes.

Discussions will be undertaken with representatives of governments of the Yukon and Northwest Territories, Quebec, and Newfoundland and Labrador to develop detailed proposals for the demonstration, to develop terms of reference for feasibility studies to select among the various possible communities, and to oversee the development and completion of contracts to design and implement the various parts of the demonstration within the community.

Funding for the program is available from fiscal year 1980-81 to fiscal year 1984-85. Total funding under the program amounts to $10 million.

IV FEDERAL FACILITIES

1. Retrofit Program for Crown-Owned Buildings

The purpose of the program is to implement capital intensive, cost-effective energy conservation measures to maximize the efficient use of energy and to effect an absolute reduction of energy consumption by the federal government.

The operation of Crown-owned buildings and facilities accounts for about 50% of the federal government's direct energy consumption. More efficient energy use standards continue to be developed for new buildings, however, by 1985, it is estimated that new construction, designed and built to these standards, will only amount to about 15% of the total government accommodation inventory.

It has been demonstrated that there is a potential for a 40% reduction in energy consumption, in existing buildings. To realize this potential, three actions are necessary.

(i) implement restrictive measures for the control of environmental systems;
(ii) implement improved routine preventitive maintenance of installed building systems;
(iii) conduct energy audits and analyses leading to retrofit of building enclosures and installed electrical mechanical systems.

Item (iii) identifies the principle feature of the retrofit program.

2. Off-Oil Conversion Program for Crown-Owned Buildings

The goal of the program is to carry out the conversion of Crown-owned buildings and facilitate movement from the use of liquid petroleum to an alternate source of fuel wherever circumstances permit.

The consumption of petroleum-based fuel in Crown-owned buildings and facilities accounts for over 22% of the federal government's direct energy consumption and represents approximately 4 million barrels of oil annually. Whilst this consumption can be reduced through the ongoing Internal Energy Conservation Program and the retrofit activities described in more detail on the accompanying page, it is not anticipated that these activites will reduce liquid petroleum consumption by more than an additional 5%. Although alternate sources of fuel will be used in new construction (unless there is no alternative course of action) 85% of the existing accomodation will be in place for at least another 15 years. A conversion program is therefore necessary.

A significant number of government-owned facilities had been converted from oil in the past three years. Some of the remaining inventory will be converted when the existing natural gas distribution network is expanded. Other heating plants might be converted from oil to coal depending upon the delivery and storage logistics.

Federal departments, Crown corporations, and agencies managing Crown-owned facilities, have as a first step been requested to identify those facilities burning oil and to specify the expertise required to study and develop conversion costs and to develop a realistic schedule together with a cash flow estimate for each facility.

V INDUSTRY

1. National Audit Program

The program will assist industrial and commercial establishments to identify areas of energy waste and to plan and implement corrective measures. The federal Government will provide funds, totalling $50 million, over a five-year period (fiscal 1980-81 - 1985-86) to be applied on the basis of an 80/20 sharing ratio with the provinces. The program will be implemented through Federal/Provincial programs aimed at encouraging energy conservation in industry and commerce (e.g., the Energy Bus Program). These existing agreements will be integrated with the National Audit Program.

The program will be administered, promoted and monitored by the provinces. Program supervision and direction will be provided by a joint Federal/Provincial Management Committee composed of two representatives from each government. This committee will meet every six months, establish procedures, guidelines, criteria, and evaluate the program and approve funds for transfer to the provincial program as required.

Eligibility and Support

All industrial and commercial establishments will be eligible for on-site energy audits and follow-up consultant advice grants. Institutions will also qualify for assistance providing they are not federally or provincially owned. Forms of support will include:

A. Expanded energy bus audit services to provide broader coverage of industrial and commercial establishments and permit follow-up visits to clients.

B. Grants will be provided to assist those firms which have already had energy audits, to plan and implement projects offering significant energy savings. The amount of support could be as high as 90% of the consultant's fee, with upper limits based on energy bills.

C. Seminars and workshops will be developed and conducted for specific sectors of industry (fisheries, greenhouses, food processing, etc.)

D. A program to develop energy demand statistics and data base for industry and commerce will be implemented.

2. Atlantic Capital Retrofit Program

The program involves the provision of grants to industrial and commercial firms in Atlantic provinces to finance a portion of their energy conservation investments. The program totals $45 million, over a five-year period (fiscal 1980-81 - 1985-86).

The program will be administered, promoted, and monitored federally through regional conservation and renewable energy offices.

Eligibility and Support

Industrial and commercial establishments will be eligible for support regardless of size but must have a specified minimum, annual energy bill. Some institutions will also be eligible providing they are not government owned. Forms of support are:

A. Grants will be provided to cover part of eligible capital costs of longer-term projects sufficient to reduce the firm's payback period to three years. Grants will not exceed 50% of eligible capital costs. The grant formula will not support projects offering payback periods under three years. The maximum grant of 50% is provided for projects with six-year paybacks.

B. Grants will also be provided for consulting costs to ensure adequate planning of retrofit projects proposed. The amount of support (project specific) will be the lesser of either 90% of consulting costs or an amount based on a formula related to the client's energy bill.

Energy conservation projects eligible for capital grants would include:

- Industrial process changes whose primary purpose is energy conservation
- Retrofit of buildings - heating, ventilating, air-conditioning, energy controls, lighting, insulation
- Waste heat recovery and utilization
- Cogeneration projects and subsidization of operator training (90% of costs, up to $10,000).

3. Industrial Energy Management Program

The extended cooperative program between the DMA, CREB, and the (15) Industry Task Forces is designed to help all manufacturing companies, regardless of size, to reduce energy costs by providing technical information, training sessions and related materials. The comprehensive program is intended for those who play a key role in energy management.

Publications

A continuing series of quarterly issues of "Energy for Canadians", will be provided to answer energy related questions. Some subjects covered are energy supply/demand trends, prices and price comparisons, energy forms and how they are obtained (nuclear, solar, tar sands, oil), and conservation measures.

Workshops for Plant Managers/Energy Coordinators

Full day technical workshops, tailored to the specific needs of a group or region, will be provided for middle management and technical staff responsible for energy efficiency improvements. These sessions, conducted by engineering consultants, will provide details on energy conservation technology and techniques, improving productivity, developing a contingency plan, measuring energy performance and the economics of energy related investments, and employee motivation. (50 workshops)

Program Implementation

Under the arrangements CREB finances in cooperation with the CMA and Industry Task Forces the development and presentation of all seminar and workshop materials. CREB also covers the cost of authoring and printing of quarterly publications and specific process and industry sector manuals on energy conservation.

4. Forest Industry Renewable Energy (F.I.R.E. II)

The first phase of this program, F.I.R.E. I, was introduced in July, 1978 to provide an incentive to the forest industries to utilize wood-waste as a source of fuel. A total of $103 million was made available for the period ending March 31, 1984 to provide grants up to 20% of the cost of capital equipment. As a result of the high level of acceptance and potential for substituion of fossil fuels this program is being expanded in coverage and eligibility.

F.I.R.E. II encourages the substitution of wood residues and other biomass for fossil fuels in the generation of energy. The target of the program is to save fossil fuels equivalent to 36 million barrels of oil per year by 1986.

The total of $103 million has been increased to $288 million to provide incentives to convert existing facilities, or install new facilities, using wood residue, municipal waste, agricultural waste, peat, or other biomass instead of non-renewable fossil fuels.

Financial incentives of 10 to 20 percent of capital costs for fuel handling and burning equipment, and electrical generators if part of a cogeneration installation, will be available to industrial, commercial, institutional or similar organizations which satisfy the program criteria.

Installations, to qualify, must be economically and financially viable, and must incorporate Canadian resources where available.
The program will continue until 1986.

5. Low Cost Energy Conservation Initiatives

Industry:

Detailed sectoral energy conservation potential studies; Industrial Task Force Development, particularly strengthening of the Task Force Coordinating Committee.

6. Class 34 - Energy Conservation Equipment Fast Write-Off

1. Introduction

Class 34 was added to Schedule B - Capital Cost Classes - of the Income Tax Act by the May 25, 1976 Federal Budget. Qualifying assets acquired by the

taxpayer after May 25, 1976 and before 1980 were eligible for this special two year write-off.

The December 11, 1979 Federal budget announced that Class 34 provisions would be extended to qualifying assets purchased before 1985 and announced significant additions to the type of assets which would qualify for the rapid write-off. These proposed changes were re-introduced in the Special Financial Package announced by the Minister of Finance April 21, 1980.

2. Provisions

Allows qualifying capital costs to be depreciated on a straight line basis over two years.

3. Coverage - Types of Assets Original

Up to December 11, 1979 the regulations were designed to cover the capital costs of cogeneration equipment (provided certain restrictions on the efficiency of oil use are met) and district heating equipment for district heating projects or systems designed to utilize biomass or garbage as a significant primary energy input.

Expansions

Coverage has been broadened to include (in addition to the above categories);

A. Solar equipment used in systems providing water heating or process heat; and solar equipment used in space heating systems in new buildings
B. Heat recovery equipment
C. Small scale hydro equipment used in projects with a maximum planned site capacity of 15 MW or less.
D. District heating equipment in systems using natural gas, coal, etc. as the primary energy source.

4. Effective Dates

Class 34 has been extended to assets acquired prior to 1985. The expanded provisions will apply to asset acquired after December 10, 1979.

5. Certification

- to qualify for placement in Class 34 for taxation purposes assets must be certified by Energy, Mines and Resources, as part of a capital project that conforms to the Income Tax Regulations pertaining to Class 34.
- EMR will be certifying investments for Class 34, taking over this function from Industry, Trade and Commerce. Prior opinions on project eligibility can be obtained from the department.
- The specifics of Class 34 coverage are somewhat complicated - further information can be obtained from:

  Tax Incentives Program Secretariat
  Conservation and Renewable Energy Branch
  Energy, Mines and Resources
  Ottawa, Ontario
  Canada

VI TRANSPORTATION

1. Motor Vehicle Fuel Consumption Standards

The Government has announced its intention to introduce legislation to enforce Fuel Consumption Standards for new motor vehicles. The current voluntary targets require that

the new car fleets of each manufacturer and importer average no more than 11.8 litres/100 km (24 mpg) for 1980 and 8.6 litres/100 km (33 mpg) for 1985. The legislated program is intended to ensure that major savings of energy from improved vehicle efficiency are attained, and that the vehicles marketed in Canada reflect the realities of vehicle operation in the cooler Canadian climate, and the availability of Canadian fuel types and feedstocks.

The legislation will require self-certification by manufacturers, with a moderate government compliance testing program. Since the legislation will be based on Trade and Commerce powers, those vehicles manufactured and sold within a province cannot technically be included when assessing a penalty for non-compliance. This mainly affects some Ontario and Quebec manufactured vehicles. Negotiations will be held with these provinces to discuss how the vehicles in question can be included.

The legislation will provide a framework for detailed study of standards for beyond 1985, and the extension of standards to include light trucks and vans.

2. Ride Sharing Centre

This $125,000 a year program will establish, in one or more Canadian communities, a pilot project ride sharing centre modelled after successful U.S. centres, to complement ongoing federal and provincial vanpool activities. The number of centres established will depend on the level of contributions forthcoming from provincial or federal governments.

The federal government's interest in vanpooling arises from the fact that this concept has already proven it can be an attractive energy saving alternative for long distance commuters. In the U.S. 12,000 vanpools are currently in operation, and the U.S. government predicts 450,000 will be in operation in 1985. Currently, most Canadian long distance commuters are 100% dependent on their automobiles and consume nearly 50% of all fuel used for commuting.

Although the centre will be primarily concerned with vanpools, it will incorporate carpool activities in its program as well. The centre will probably offer an on-line computer matching service.

The major tasks to be performed by the centre will be as follows:

1. Animators will visit employers and other organizations to stimulate interest in the concept.

2. The centre will assist interested parties in setting up and administering vanpool programs on both employer-specific and multi-employer bases.

3. The centre will act as a community-wide matching centre. An individual who wishes to join a vanpool will call the centre, and the centre's matching service will either place him/her in a pool, or insert the name on a waiting list until such time as there are enough people for the particular route.

3. Automobile Workshops and Seminars

Contributions of $50,000 a year will be available to assist automobile driver associations, and other organizations, to conduct workshops, seminars, and demonstrations concerning energy conserving driving and operating techniques. This program has been devised in recognition of the large amounts of energy which can potentially be saved by changing driving habits and attitudes towards automobile use. The program will be complemented by a study on attitudes and awareness of fuel conserving measures related to automobiles.

4. Truck Energy Conservation Demonstration

This $125,000 a year program is intended to serve the information needs of small to medium size truck fleets. Part of the funds available will be used for contributions to

encourage workshops and seminars. The other focus of the program is to demonstrate the effectiveness of a service to truck owners to assist them in vehicle selection, optimization of operations, and recommended driver training for energy conservation. Program delivery through the energy bus program for industry is being investigated.

5. Propane Vehicle Conversion Program and Propane Vehicle Conversion Grant Program

The Government is anxious to promote the use of propane as a motor fuel in areas of the country where propane is in surplus supply. More than 60,000 barrels of the propane produced in Canada each day are surplus to current domestic needs; this is equivalent to about 8% of our daily gasoline usage. The Government's objective is to direct at least one-quarter of this surplus into vehicle fuel markets by 1985, representing about 100,000 propane vehicles.

Propane is an attractive, clean-burning motor fuel, and will give an excellent performance, longer engine life, and reduced maintenance costs. In many provinces it sells for less than gasoline. To help encourage propane use, the Government is offering a $400 grant for commercial road vehicle conversion. The target of 100,000 vehicles will be reached only with the continuing efforts of industry and provincial governments to ensure an adequate supply of fuel and equipment and a climate conducive to conversion.

Propane surpluses and exports occur in western Canada and Ontario. These provinces have all recognized the value of directing more propane to motor fuel markets. British Columbia has removed sales tax from propane conversion equipment and reduced the road tax on propane. Alberta already enjoys a considerable motor fuel use of propane, but there is potential for more. Manitoba and Ontario are involved in demonstrations of propane in vehicle fleets, and in a major initiative, Ontario has removed the road tax and new vehicle sales tax for "alternative fuels", including propane.

Provinces east of Ontario have not seen fit to encourage propane as a motor fuel. Propane is not in surplus supply in these regions, except perhaps seasonally, and its retail price exceeds the domestic price of gasoline. Very little motor fuel use is likely under these circumstances.

Safety is not a problem if conversion and fuel handling are done properly. However, the current lack of appropriate and uniform safety codes across the country is a concern that is being addressed by EMR and Transport Canada in cooperation with provincial governments and the Standards Council of Canada.

The retail distribution network for propane in many parts of Canada may not currently be adequate to support significant propane use in private vehicles. Commercial fleets are the initial market. The supply of conversion equipment and qualified service personnel for propane carburetion may currently be limited in Canada, but the industry appears to be growing aggressively.

The grant applies to new propane road vehicles and to the conversion of gasoline or diesel-fueled road vehicles to operate on propane or propane/diesel.

6. Federal Government Propane Motor Fuel Demonstration

The Federal Government intends to demonstrate the use of propane as a motor fuel within its motor vehicle fleet. This demonstration is complementary to the National Energy Program announcement of a commercial fleet $400 grant program for conversion to propane fuel.

The federal demonstration aims to have 8,000 vehicles powered by propane in 1985. Four thousand in-use vehicles will be retrofitted and 4,000 vehicles will be purchased new.

The program is intended to provide two major outputs. The first output will involve information while the second will involve the expansion and enhancement of the supply and distribution of propane, propane carburetion equipment (for retrofit and original equipment use), and the propane service industry.

Secondary outputs of the program will include research and development activities which will pave the way for subsequent demonstrations involving other gas based fuels such as natural gas and hydrogen.

VII RESEARCH AND DEVELOPMENT

1. Research and Development in New Liquid Fuels

In its recent Discussion Paper on Liquid Fuel Options, the Government identified technical and economic barriers to the viability of many fuel options in Canada today, options such as coal liquids, compressed natural gas, alcohols and artificial gasoline. The Government is committed to research and development work to address these barriers and secure our liquid fuel options. In some cases it is important to do work to bring an option to the point of technical feasibility, as a contingency for commercial development, should the need arise. In other cases, the Government would welcome commercial activity as soon as technical and market risks permit. Different research strategies may be appropriate to different situations.

The Government is prepared to spend $50 million and $100 million dollars on research and development of new liquid fuels over the next three years, depending on the capabilities of the scientific, university, and industrial communities to meet the challenges of this opportunity. The Government expects research funds from Canadian industries and provincial governments to supplement this support. In many cases, joint sponsorship of work will permit the most fruitful definition of priorities and approach, and will ensure the technical advances reach those most capable of promoting their continuing development and commercial exploitation.

It is particularly important that Canada increase its participation in the rapidly growing international community of work in alternative fuels and changing fuel processes and feedstocks. The costs of technological development in these areas are enormous, and several countries often collaborate on individual projects. It is not uncommon for the scientific, capital, and natural resource ingredients of a project to be contributed by different participants. Canada is not frequently enough one of those participants.

The Government will place priority on participation in international work of interest to Canada, and will support sufficient work in the country to ensure that our contribution is of a high calibre and we are able to train people to expand the work and support the industrial growth that should follow. In other cases, the amount of work that should be supported in Canada may be much greater than this; in instances where a technical problem or fuel option is unique to Canada and not pursued elsewhere, or where Canada has an opportunity to assume world leadership in a developing technology of widespread interest, special efforts should be made.

The Government welcomes research proposals, ideas, support, and talent that could contribute to unlocking our abundant liquid fuel options.

2. Energy Conservation R & D Under NEP

Under the National Energy program additional funds will be available for energy R & D in four areas:

Conservation
Alternate Fuels
New Sources
Conventional Fuels in Canada Lands

These additional funds are as follows:

FY 81-82	$35 million
82-83	$75 million
83-84	$125 million

The allocation of these funds among the four areas is unresolved at this time.

The new funds in energy conservation will be allocated to programs in:

Industry
Buildings
Transportation
Community systems
Demand Studies

It is envisaged that these new funds will require a reorganization of the Federal energy conservation R & D program with an emphasis on the extension of contracting our procedures with industry for developmental and transfer programs.

VIII RENEWABLES

1. Application of the Canadian Oil Substitution Program (COSP) in Remote Communities

The COSP Program consists of two parts (1) grants of up to $800 for conversions and (2) funds for expansion of energy systems or infrastructure. The grants to individual homeowners apply in the same way in remote communities as in other parts of Canada. Similarly, extension of provincial electrical grids may be eligible for support under the infrastructure budget where the economics are reasonable. In addition, the infrastructure budget may in principle be used for other projects in remote communities, such as the provision of small scale hydroelectric generation or measures to increase the efficiency of use of energy on the scale of the individual or the community, such as heat recovery and distribution to a number of properties.

The program will be delivered federally through regional offices in each province.

2. Canadian Oil Substitution Eligibility of Wood-Burning Systems

The following criteria define in a preliminary way the conditions under which wood stoves and furnaces are eligible for conversion grants under the Canadian Oil Substitution Program. They are subject to negotiation with the provinces and therefore may vary in detail from one province to another.

1. Displacement

   The wood stove(s) or furnace must be designed to displace at least 50% of the oil required for space heating.

2. Safety

   Only equipment certified by the Canadian Standards Association, the Underwriters' Laboratory of Canada,* or some other recognized standards body is eligible. The equipment must be installed safely, including the provision of a safe chimney. Inspection requirements will be determined by the province. The costs of installation, including the chimney, are eligible expenses.

3. Performance

   Only airtight stoves and wood furnaces will be eligible.

4. Hybrid Systems

   Combination furnaces running on wood and oil are eligible, provided they satisfy the criteria noted above. Similarly, hybrids running on wood and electricity are eligible except in provinces in which electricity is generated predominantly from oil (Atlantic Canada and the Territories).

In the interim period before formal agreement is reached with the provinces, wood-burning systems which satisfy the above criteria will be eligible for a conversion grants.

* The relevant standards are: ULC-S627; CSAB 366
(A joint ULC/CSA Standard is pending.)

3. Off-Oil Conversion Grants

Eligibility: available to households and businesses converting from oil to natural gas, electricity, renewables (solar, wood, etc.), other. Taxpayers choose the most desirable course of action. Conversions from oil undertaken after October 28, 1980 are eligible for grants.

Size: 50% of conversion costs to a maximum grant of $800

Taxation: grants are taxable income

Exceptions: in the Atlantic Provinces conversion from oil to electricity will not be eligible until Atlantic utilities reduce their dependence on oil fired generation

Administration: conversions to natural gas and electricity will be administered by the public utilities concerned. For renewables etc. details will be announced. KEEP YOUR RECEIPTS

4. Accelerated Demonstration of Solar-Domestic-Water Heating

Objectives

The objectives of this program are to demonstrate large-scale deployment of solar-domestic-water heating, to establish preliminary economies of scale, to demonstrate a preliminary commercial infrastructure for the installation and maintenance of solar-heating equipment, to contribute to the development of a private market for solar-heating equipment, and to provide experience and information essential to the on-going development of policy in active solar heating.

Method of Implementation

The program will be run by Energy, Mines and Resources through contracts to project managers to administer projects of typically 100 or more solar-heating systems in any given location. The main contractor will, as necessary, sub-contract to suppliers of solar-heating equipment, to owners of property (either building developers or home owners), and to companies that will install and maintain the systems.

Solar-Heating Systems

The program will deal exclusively with suppliers of complete solar-heating systems, so that some economies of scale will be realized immediately, and further economies in full comercial production can be accurately estimated. Solar-domestic- water heating systems accepted for this program will have high Canadian content, good reliability, durability and thermal performance, and be competitively priced.

Financial Participation

The financial participation of householders or builders is required in the amount of $500 per solar-domestic-water heating system. The balance of the cost of the system and its installation, including a fee for management of the project, will be contributed by Energy, Mines and Resources. The ownership of the system shall reside with the homeowner following approval of the installation.

REFERENCES

1. Baird, W.F., and G.R. Mogridge. Estimates of the Power of Wind-Generated Water Waves at some Canadian Coastal Locations. Ottawa, National Research Council, 1976. (Report LTR-HY-53)

2. Bay of Fundy Tidal Power Review Board and Management Committee. Reassessment of Fundy Tidal Power. Ottawa, 1977.

3. Canada. Energy, Mines and Resources Canada. Conservation in Canada: Programs and Perspectives. Ottawa, 1977. (Report 77-7)

4. Carhart, S.S., et al. Creating New Choices. Arlington, Va., Mellon Institute, 1980. (Energy Productivity Report Number 3)

5. Daborn, G.R., ed. Fundy Tidal Power and the Environment. Wolfville, N.S., Acadia University Institute, 1977.

6. Hollands, K.G.T., and J.F. Orgill. Potential for Solar Heating in Canada. Waterloo, Ont., University of Waterloo Research Institute, 1977.

7. Jessop, A.M. Geothermal Energy from Sedimentary Basins. Ottawa, Energy, Mines and Resources Canada, 1976. (Geothermal Series No. 8)

8. Love, P., and R. Overend. Tree Power: An Assessment of the Energy Potential of Forest Biomass in Canada. Ottawa, Energy, Mines and Resources Canada, 1978. (Report ER 78-1)

9. McGowan, J.G., and W.E. Heronemus. Gulf Stream Based Ocean Thermal Power Plants. Presented at the American Institute of Aeronautics and Astronautics and the American Aeronautical Society Solar Energy for Earth Conference, Los Angeles, Calif., April 21-24, 1975. (AIAA Paper No. 75-643)

10. Ontario Hydro. Design and Development Division. An Examination of the Potential for Solar Energy Utilization in Ontario. Toronto, 1975. (Report No. 75092)

11. Ontario Hydro. Energy and Environmental Studies Dept. A Review of Large Scale Generation Using Windmills. Toronto, 1975. (Report No. 75117)

12. Ostrom, A.R. Economic Analysis of Domestic Solar Water Heating. Ottawa, Energy, Mines and Resources Canada, 1979. (CREB Working Paper)

13. Ostrom, A.R. Megawatt Scale Wind Turbines. Ottawa, Energy, Mines and Resources Canada, 1979. (Discussion Paper)

14. Shawinigan Engineering Co. Ltd. Large Capacity Vertical-Axis Wind Turbine Generators. Report done for the National Research Council. Montreal, 1980. (Not currently available)

15. Swain, H., R. Overend, and T. Ledwell. Canadian Renewable Energy Prospects. Ottawa, Energy, Mines and Resources Canada, 1978.

16. Trimble, L.C., and B. Messinger. Ocean Thermal Energy Conversion System Evaluation. Presented at the American Institute of Aeronautics and Astronautics and the American Astronautical Society Solar Energy for Earth Conference, Los Angeles, Calif., April 21-24, 1975. (AIAA Paper No. 75-616)

17. United States. National Science Foundation. A Technology Assessment of Geothermal Energy Resource Development. Washington, D.C., 1976.

18. White, D.E. Geothermal Energy. Washington, D.C., U.S. Geological Survey, 1965. (Circular No. 519)

ENVIRONMENTAL AND SAFETY CONCERNS OF HYDROELECTRIC POWER GENERATION

This paper is based on a draft prepared by the Department of the Environment.

November, 1980

TABLE OF CONTENTS

1. INTRODUCTION

The use of water power for electricity generation has been praised as the wise use of a renewable resource and one which will have fewer negative impacts on the environment than many other methods. However, such developments, particularly on the large scale often contemplated, can be very destructive of the natural environment and present grave risks to communities nearby. While environmental and biological effects will vary from one site to another and one project design to another, some general statements regarding negative impacts can be made.

The most noticeable concerns are loss of land and land-based resources such as timber, agriculture, and wildlife; the conversion of wild rivers into regulated rivers and lakes thus modifying the opportunity for fishing, hunting, and camping; and the change of the local ecology from a river environment to a lake environment.

Additional, but less noticeable, problems are erosion, sedimentation, thermal, and water quality changes, all of which are directly or indirectly associated with these developments. There is a progressive change in plant and animal composition from forms which have adapted over a long period of time to a river environment to those which frequent calm waters. Any diversion from one watershed to another can allow the introduction of different types of life from one system to another with effects that can be far reaching.

Construction practices and the flooding of land associated with hydro-electric projects represent impositions of varying degrees on local populations; in some remote areas, these effects can present a drastic disruption of a traditional way of life for native people while in more developed areas, the effects can be of an economic rather than a social nature.

Hydroelectric development can also pose a potential hazard to human life. Increased earthquake activity associated with hydro sites and dam failures have been recorded throughout the world in recent years. This increased seismic activity is reported to be related to the depth and extent of the reservoir, with the risk being higher in large reservoirs with depths in excess of 100 metres. Fortunately, induced earthquakes have not been large and thus have not caused serious damage. There have been no known dam failures associated with hydroelectric projects in Canada.

2. CLASSIFICATION OF EFFECTS

The environmental effects of a hydroelectric project can be divided into two primary areas of concern: the reservoir, and downstream.

i) The Reservoir Effects

Land Based

When a river is dammed, a reservoir or lake is formed with a consequent loss of land area and the resources it supports. Usually it is possible to economically evaluate such losses, particularly if the resources are of commercial importance, such as standing timber, agricultural land, or mineral deposits. For example, timber may be harvested before flooding. However, the harvesting decision has to be based not only on the monetary value of the timber, but also on the projected use of the reservoir for purposes other than water storage. In remote areas where recreational demands are not high or the economics of removing the timber are prohibitive, reservoir clearing may be judged unnecessary. In areas accessible to the general public and with the potential for recreational development or municipal usage, partial or clear cutting of the forest may be a necessary cost of the project.

In addition to the obvious losses of land-based resources through flooding, there can also be more subtle changes in shoreline resources which reduce their value and usefulness. Such changes include raising the water table, with the resulting water-logging of vegetation and subdivision of large tracts of land by flooding.

The same economic evaluation is not always possible for those resources that have an aesthetic or recreational appeal and thus fall within that grey area where dollar values are difficult to estimate. Value judgements, in these situations, have to be made on social needs and/or demands. For projects which are situated in areas accessible to the public or which subsequently make an area accessible to the public, the recreational potential must be carefully considered. Not only may hydro developments increase opportunities for fishing and hunting, they may also introduce such recreational uses as camping, increasing the people pressure on the life of the area. This pressure can lead to destruction of fish and animal feeding areas, overexploitation of some species to the point of extinction and an increased incidence of forest fires.

Fish Life

When a watercourse is blocked by a dam, the normal passage of fish migration is blocked also. If compensating structures, such as fishways or artificial spawning areas, are not constructed, fish stocks can be virtually wiped out, despite a certain degree of adaptability. Even if facilities are constructed to allow migration upstream past the dam, some deterioration of stocks will still take place since a significant proportion of young fish will be destroyed on their downstream migration through the turbines.

Shoreline

The creation and regulation of a reservoir poses certain ecological problems. Reservoirs normally fill during the period of snowmelt (spring to early summer), maintain the high water during the period of summer, and drawdown during the late fall and winter. Under natural conditions the peak periods for rivers and lakes are relatively short and the water levels generally fall before the growing season is very far advanced. As a result the shorelines of natural lakes and rivers are protected by a cover of vegetation that extends down to the low water mark, and in wetland areas extends out into the lake or stream. In reservoirs, however, the extended high water period inhibits vegetative growth in the drawdown zone so that when the water is drawn off, extensive barren areas are exposed. The shoreline of a newly created reservoir is exposed to the action of waves, ice scouring, and groundwater seepage, all of which increase the erosive process.

In clearing a reservoir, it is ecologically desirable to leave at least part of the forest cover to retard erosive processes. Post-audits of reservoirs have shown that where shorelines lack some vegetative protection, the action of the waves creates a broad sterile zone between the high and low water marks, although such areas sometimes develop into beaches as the reservoir ages.

In the north of Canada, the development of reservoir shorelines on permafrost is of particular concern. When the permafrost is flooded, it melts and the surface soils with their vegetative cover slump into the reservoir. This process repeats itself in an erratic and unpredictable way until the shoreline reaches to bedrock or a relatively stable gravel formation.

Sediment

Damming a river reduces the speed of the water flow significantly and any sediment being transported down the river is deposited on the bottom of the reservoir. This deposition plus the results of shoreline erosion can eventually fill in the reservoir to such an extent that it may no longer be useful.

Water Quality

During reservoir filling, plant nutrients and other inorganic solutes may be leached from the flooded soil or released through the decay of flooded vegetation. This release of nutrients to the reservoir frequently results in a significant rise in productivity that is reflected up through the food chain to its most obvious manifestation, a rapid rise in the fish population. This bloom usually lasts only a few years and is followed by a gradual decline, during which the reservoir's productivity stabilizes at a somewhat lower level.

It is also possible that toxic materials may be leached from the flooded soils and their effects reflected through the food chain. Mercury, for example, has been found in fish in newly created reservoirs in areas where it has not been produced or used in manufacturing. Similarly, in farming areas where crop lands have been flooded, the increase in pesticides in the reservoir water is often measurable in the fish.

Reservoirs created on rivers flowing through industrial or residential areas become sinks for the waste materials that are discharged into the water. In the slower-moving and deeper parts, the oxygen concentrations will be somewhat lower than in rivers, hence the breakdown of foreign organic matter will be slower. These phenomena contribute to the deterioration of water quality within the reservoir.

Thermal

Unlike rivers, which tend to be of one temperature throughout because of the faster movement of water, lakes and reservoirs experience a thermal stratification process during which layers of relatively colder and warmer waters occupy certain depths of the reservoir and actually change their positions according to the seasons of the year. This process of changing temperatures could drastically affect any species with a narrow temperature tolerance by forcing them away from their natural feeding and spawning grounds.

Species Diversity

As a reservoir is created and the speed of the flow reduces, plants become established and nutrient recycling increases. As the reservoir fills, many species of land plants and animals die. Those with a good capacity to adapt may persist for some time before being replaced by aquatic forms. Species diversity, generally high in rivers due to current flow variability and habitat diversity, declines through selection and elimination with the establishment of a lake environment. Those that are adaptable to the new physio-chemical, reproductive, and feeding conditions survive; the remainder migrate or are eliminated. The most noticeable changes are the migration of the animals and the destruction of terrestrial plant life, along with the introduction of shoreline or marsh-type plant life. At the same time, fish species are changing. The reservoir drawdowns inhibit or destroy the spawning success of certain species of fish (depending on the timing and extent of the drawdown). Species that require vegetative growth on which to deposit their spawn, or those species of fish which during their early life stages use vegetated areas as a source of food and cover are most affected if the drawdown zone develops into an extensive barren mud or rocky flat. Species adaptive to a lake environment will now flourish and become predominant where they were once secondary.

If the hydroelectric project involves the diversion of water from another watershed, foreign species may be introduced which could carry organisms harmful to the existing species.

ii) Social Effects

Life Style Impacts

When hydroelectric projects were small, the social impacts did not appear to be very significant. During the past three decades however, some projects have increased to such a size that thousands of square miles are affected. The disruption in the traditional way of life of native people and other remote populations is

extensive. Lives which are dependent upon hunting and fishing can be severely disrupted through the flooding of vast tracts of land and even the increased access to remote territory and the experience of the construction period can modify a traditional existence significantly.

Hazards to Human Populations

Records of earthquakes occurring in Canada during or after reservoir filling are sparse. The only well-established instance of induced seismic activity in Canada occurred during the filling of the Manicouagan 3 Reservoir in Quebec in October 1975, registering 4.3 on the Richter scale.

The risk of catastrophic dam failure poses a direct threat to human life and property. Although no dam failures associated with hydroelectric projects have been recorded in Canada, some world statistics are available. During the current century in Western Europe and the United States, 70 major dam failures occurred, about 13 of those dams associated with hydroelectric generation. These failures involved a large loss of life. Of the official reasons for these failures, 35 per cent were caused by insufficient spillway capacity, 25 per cent by foundation problems, and the remaining 40 per cent by seismic activity, faulty operation, wave action, and miscellaneous effects.

None of the 144 major dams registered in Canada have failed, perhaps because of conservative design or strong foundations. If the international estimates of failure rates were applied to Canadian statistics, a major dam failure could be expected every 150 years. Although there are definitely hydroelectric projects in Canada whose siting is such that a failure of the dam would cause a significant loss of life, the largest projects are situated in more remote areas where destructive forces would be somewhat dissipated by the time they reached densely populated areas.

iii) Downstream Effects

The environmental consequences of a hydroelectric development are more significant in the downstream portion of the system, although it may not appear so. Many of the changes that occur below the dam are opposite to those that take place above it. In a reservoir, silt, organic, and inorganic material accumulate, while below the dam they are reduced. The natural range of level fluctuation in the reservoir is usually increased through controlled outflow, while the downstream range of levels is reduced. These all have some effect, often many miles below the dam.

Again, impacts are site specific. Generally, the severity of the downstream effects are in proportion to the amount of storage behind the dam.

Shoreline

The regulation of downstream flows normally results in increased short-term and decreased long-term fluctuations in water level, stabilizing the river bank. The disruption of the natural rhythm of fluctuation has number of effects on river-dwelling organisms, particularly bottom-dwelling insects and molluscs. The species composition is often changed considerably and while there is a decrease in diversity, the increased long-term constancy of flow provides a more stable substrate (if the short-term fluctuations are not too extreme), increasing the standing crop of organisms

Sediment

A reservoir retains much of the suspended material brought into it from upstream. The loss of this material will significantly affect the productivity of the downstream area, particularly that immediately below the dam. Rivers, unlike lakes and reservoirs, are largely dependent upon upstream sources of nutrients for the production of the basic food materials needed to support their animal populations. The loss of organic material to the reservoir is reflected in lower productivity in the food chain. Since the reservoir acts as a sediment sink, the turbidity immediately below the dam is usually less than that of the freeflowing

river, resulting in some increase in primary productivity and consequently more food for the fish. Unfortunately, the clearer water also exposes the fish to higher predation.

A delta is often the most productive landform that develops in a river system. It usually consists of a series of wetlands interspersed with lakes and ponds and is maintained at a very early stage of succession by the natural fluctuations of the river. During the spring flood when delta building occurs, the mainstream flows under natural conditions are sufficiently strong to have a backwater effect at the tributary mouth. With regulated and lower spring flows in the main stream, the flood speed of the tributary are sufficiently strong to have an erosive and destructive effect on the delta. Consequently, much of the most productive downstream ecosystem is degraded or destroyed.

Water Quality

The design of the dam and power station is an important factor in assessing possible downstream environmental effects. If the water intake to the penstock is situated well below the surface, the water discharged downstream will be colder than normal in the summer period and warmer than normal during the winter period. The changes in temperature that arise with deepwater withdrawal could result in changes in the downstream distribution of some organisms and fish, as many species of each are tolerant over a narrow range of temperatures. Such thermal changes could also have an effect on the timing of downstream freeze-up and break-up which in itself influences plant and animal communities.

Gas bubble disease usually occurs when water passing over a spillway entrains air forced into solution when the water enters the plunge basin. Through normal feeding and breathing activities, the gases at high concentrations enter the bloodstream and tissues of the fish, causing death or tissue destruction. Although this condition can correct itself downstream, fish can still be exposed to this nitrogen supersaturated water for a significant distance from the dam.

iv) Associated Effects

Climate

Another concern is the modification of local climatic conditions. Limited work has been done in Canada on the climatic effects of reservoirs, but indications are that localized reductions in the annual range of temperatures is possible; that is, the mean temperature in the spring will be colder and in the fall slightly warmer; night-time temperatures will generally be warmer nearer the water so that local frost-free seasons at the shoreline will be extended by 5 to 15 days. In the North, the break-up of ice at the mouths of the rivers is speeded-up by the spring floods. With regulated flows, the magnitude of the flood would be lessened, break-up would be delayed, and locally, the onset of the growing season could be later than normal.

Transmission Lines

Transmission lines are associated features of hydroelectric installations not necessarily limited to the reservoir or downstream areas. With the more remote sites now being developed, vast areas of unexploited territory are being opened by cutting transmission corridors. While the amount of land used for transmission corridors can be significant if associated with a large-scale remote project, total land usage is not destroyed near populated areas, where farming and ranching co-exist. Investigations into the electro-magnetic radiation effects of transmission lines on humans and animals have so far proven no health hazard.

3. CONCLUSION

While generally considered a benign source of energy, hydroelectric developments on the scale now necessary can be very destructive of the ecology of the area. The difficulties of such large-scale hydroelectric developments are exemplified by the James Bay project in Quebec, a development which has radically effected a very large land area, changed the course of major rivers and had a tremendous impact on the lives of the native communities in the area.

While most of the remaining developments being looked at are on such a large scale, it should not be forgotten that even small dams or run-of- the-river turbines will have some effect on the ecology of the water and land in the area.*

---

* Further details on environmental effects and mitigative measures are available through a paper entitled Environmental Effects of Dams and Impoundments in Canada: Past Experience and Future Prospects, by R.M. Baxter and P. Glaude of Environment Canada. Their paper served as the major source material for this overview.

Ackerman, W.C., et al. Man-made Lakes: Their Problems and Environmental Effects. Washington, American Geophysical Union, 1973.

American Fisheries Society. Reservoir Fishery Resources Symposium. Athens, Georgia, University of Georgia, 1967.

Avakyan, A.B. "Problems of Creating and Operating Reservoirs." Soviet Hydrology No. 3:194-199, 1975.

Baxter, R.M., and P. Glaude. Environmental Effects of Dams and Impoundments in Canada: Past Experience and Future Projects. Ottawa, Environment Canada, unpublished.

Buckler, S.J. Some Climatic Effects of a Prairie Reservoir on Shoreline Stations. Ottawa, Atmospheric Environment Service, 1973. (EEC 786)

Collins, G.B. "Effects of Dams on Pacific Salmon and Steelhead Trout." Marine Fisheries Review, 38:34-46, 1976.

Davis, R., R.B. Smith, and G. Goos. Predicting Reservoir Quality Changes - A Laboratory Investigation. In Proceedings of the Symposium on the Lakes of Western Canada. Edmonton, 1973. pp. 40-54.

Dominy, C.L. "Recent Changes in Atlantic Salmon (Salmo salar) Runs in the Light of Environmental Changes in the Saint John River, New Brunswick, Canada." Biological Conservation 5:105-113, 1973.

Efford, I.E. "Assessment of the Impacts of Hydro-dams. Journal of the Fisheries Research Board of Canada, 32:196-209, 1975.

Ellis, M.M. " Freshwater Impoundments." Transaction of the American Fisheries Society, 71:80-93, 1941.

Fischer, S.G., and A. LaVoy. "Differences in Littoral Fauna due to Fluctuating Water Levels Below a Hydroelectric Dam." Journal of the Fisheries Research Board of Canada, 29:1472-1476, 1972.

Geen, G.H. "Effects of Hydroelectric Development in Western Canada on Aquatic Ecosystems." Journal of the Fisheries Research Board of Canada, 31:913-927, 1974.

Geen, G.H. "Ecological Consequences of the Proposed Moran Dam on the Fraser River." Journal of the Fisheries Research Board of Canada, 32:126-135, 1975.

Gill, D. Damming the Mackenzie: A Theoretical Assessment of the Long-Term Influence of River Impoundments on the Ecology of the Mackenzie River Delta. In: Proceedings of the Peace Athabasca Delta Symposium. Edmonton, University of Alberta, 1971. pp. 204-222.

Gill, D. The Mackenzie River Delta and Upstream Hydroelectric Developments. In: Mackenzie Delta: Priorities and Alternatives. Conference Proceedings, 3 and 4 Dec. 1975. Canadian Arctic Resources Committee, 1976.

Gill, D., and A.D. Cooke. "Controversies over Hydroelectric Developments in Sub-Arctic Canada." Polar Record 17:105-127, 1974.

Gough, D.J. and W.I. Gough. "Load-induced Earthquakes at Kariba II." Geophysical Journal of the Royal Astronautical Society. 21:79-101, 1970.

Gupta, H.K., and B.K. Rastogi. Dams and Earthquakes. Amsterdam, Elsevier, 1976.

Harvey, H.H. Gas Disease in Fishes - A Review. In: Chemistry and Physics of Aqueous Gas Solutions. Edited by W.A. Adams, et al. Princeton, N.J., The Electrochemical Society, 1975. pp. 450-485.

Kachngin, E.G. "The Destructive Action of Waves on the Water Reservoir Banks." I.A.S.H. Symposium Garda 1:511-517, 1966.

Kellerhalls, R., and D. Gill. Observed and Potential Downstream Effects of Large Storage Projects in Northern Canada. In Proceedings of the 11th Meeting of the International Commission on Large Dams, 1973. pp. 731-754.

Kisslinger, C. "A Review of Theories of Mechanisms of Induced Seismicity." Engineering Geology 10:85-98, 1976.

Kittrell, F.W. "Effects of Impoundments on Dissolved Oxygen Resources." Sewage and Industrial Wastes 31:1065-1098, 1955.

Lagler, K.F. Man-made Lakes; Planning and Development. Rome, F.A.O., 1965.

Larkin, P.A. The Environmental Impact of Hydro Power. In: Energy and the Environment. H.R. MacMillan Lectures for 1971. University of British Columbia, Institute of Resource Ecology, Vancouver, 1972.

Lowe-MacConnell, R.H., ed. Man-made Lakes. London, Academic Press, 1966.

Mark, R.K., and D.E. Stuart-Alexander. "Disasters as a Necessary Part of Benefit-cost Analyses." Science 197:1160-1162, 1977.

Milne, W.G., and M.J. Berry. "Induced Seismicity in Canada." Engineering Geology 10:179-276, 1976.

Newbury, R.W., K.G. Beatty, and G.H. McCullough. Initial Shoreline Erosion in a Permafrost Affected Reservoir, South Indian Lake, Canada. In Proceedings on the Third International Conference on Permafrost. Edmonton, July 10-13, 1978. pp. 833-839.

Park, E.T. Literature review on "Effects of Reservoir Impoundment on Water, quality". Ottawa, Inland Waters Directorate, Dept. of the Environment 1975.

Simpson, D.W. "Seismicity Changes Associated with Reservoir Loading." Engineering Geology 10:125-150, 1976.

Soucy, A. "James Bay Hydroelectric Development. Evolution of Environmental Considerations." Canadian Water Resources Journal 3:54-88, 1978.

Symposium on Environmental Impact Assessment and Hydroelectric Projects: Hindsight and Foresight in Canada. Proceedings. Journal of the Fisheries Research Board of Canada. 32:97-209, 1975.

Troxler, R.W., and E.L. Thackson. "Predicting the Rate of Warming of Rivers Below Hydroelectric Installations." Journal Water Pollution Control Federation 49:1902-1912, August, 1977.

Vonwickel, E., and S. Orvig. Meteorological Consequences of Natural or Deliberate Changes in the Surface Environment, General Principles with Examples from the James Bay Region. Montreal, McGill University, 1974. (Meteorology, No. 112)

ENVIRONMENTAL, HEALTH AND SAFETY AND ASPECTS OF COAL-FIRED ELECTRICAL POWER GENERATION IN CANADA

This paper was prepared jointly by three federal government departments. The environmental section was contributed by Environment Canada, the health aspects by Health and Welfare Canada and the safety aspects by Energy, Mines and Resources Canada.

November, 1980

Table of Contents

Page

Tables:

Figures:

I: INTRODUCTION AND SCOPE

The options available for electrical system expansion for the foreseeable future, in provinces without undeveloped economic hydro potential, will be coal-fired or nuclear power plants. Increasingly, choices among fuel systems must be guided not only by economic considerations but also by comparison of their health and environmental effects. This discussion is intended to serve as a brief overview of the current and potential environmental and health impacts of coal-fired electrical power generation in Canada.

The largest increase in coal utilization in Canada during the past twenty years has occurred in the electric power generation industry. In 1979, approximately 80 per cent of the 25 million tonnes of coal consumed were used to produce electricity (1). Coal-fired generating stations now represent roughly 17 per cent of the country's total electrical generating capacity, 50 per cent of the fossil-fueled (oil, gas, and coal) capacity and about 2.4 times the presently installed nuclear generating capacity (11). There are plans to expand capacity in Nova Scotia, New Brunswick, Ontario, Saskatchewan, and Alberta such that coal-fired capacity will rise from 14 000 MW in 1979 to 20 000 MW in 1991, an increase of roughly 6 000 MW.

The locations of the present thermal coal mines and coal-fired generating stations in Canada are indicated in Figures 1 and 2 respectively. At present, while more than 60 per cent of the coal-fired generating capacity is located in Ontario, more than 85 per cent of the thermal coal mined in Canada is in Alberta and Saskatchewan. More than 99 per cent of this country's estimated coal reserves of 235 billion tonnes (measured, indicated, and inferred) are in the three most westerly provinces (9).

The identification of the environmental and health impacts of coal-fired generation requires a description of the entire coal fuel trajectory, since there are hazards of different kinds and severity at each stage. The trajectory can be described more specifically as being composed of extraction (mining), processing, transportation, and combustion (power generation). With the exception of processing, which is currently not widely practised for Canadian thermal coals, the fuel and the environmental impacts resulting from each stage are presented schematically in Figure 3. This diagram places the impacts in perspective by quantifying their relative magnitude and severity.

II: ENVIRONMENTAL IMPACTS

1. Extraction (Mining)

i. Quantities and Methodologies

Approximately 17.4 million tonnes of thermal coal, or about 70 per cent of the Canadian consumption for power generation was mined in Canada in 1979 (1). The remainder was imported from the United States for use in Ontario. With the planned increase in generating capacity and the use of more western Canadian coal in Ontario power plants, thermal coal extraction is expected to reach 40 million tonnes per year by 1990.

There are two basic methods for extracting coal: surface mining and deep (underground) mining. More than 90 per cent of all Canadian thermal coal is recovered from surface mines which, with the exception of two small operations in the Maritimes, are located in Western Canada (10).

Surface mining techniques can be subdivided into "open-pit" and "strip" operations. Open-pit mining is used most often in mountainous regions where coal seams are irregular and highly localized. This technique is a vertical operation with the excavation becoming progressively wider and deeper. Strip mining is carried out predominantly on the Prairies where generally flat-lying coal seams occur. This technique is a horizontal operation with excavation of overburden and extraction of coal proceeding along the seam.

ii) Impacts on Land, Water and Air

Surface mining operations affect the land and air environments near them in undesirable ways if land reclamation is not practised and if the mining is not carried out in a careful and controlled manner. Some of the key undesirable land impacts are as follows:

Figure 1 Principal Coal-Fueled Power Stations in 1979

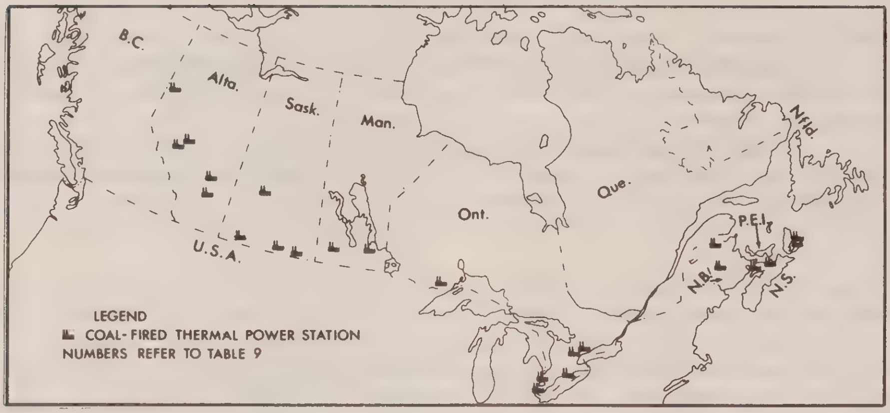


Figure 2 Principal Thermal Coal Mines in 1979

Figure 2 Principal Thermal Coal Mines in 1979

Source: Adapted from Canadian Minerals Yearbook 1975.

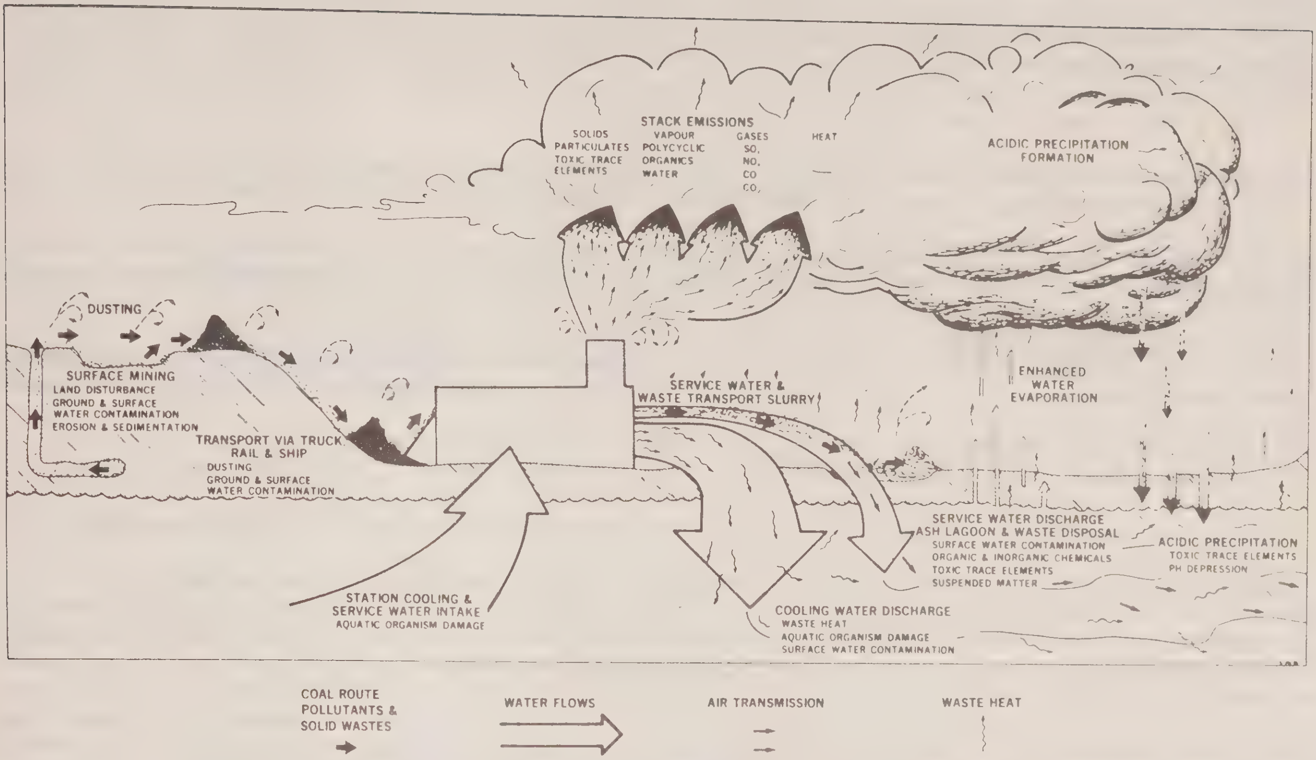


FIGURE 3 ENVIRONMENTAL DISTURBANCES FROM CANADIAN COAL FUELED POWER GENERATION

Source: Environmental Protection Service, Environment Canada

(a) the creation of large areas of barren landscape with attendant removal of this land from the agricultural, forestry, and recreational resource base. Based on some Canadian strip mining operations (8, 19), the area of land disturbed to supply a 1 000 MWe plant ranges from 50 to 200 hectares per year.* If the average lifetime of such a plant is 30 years, the total area disturbed could range from 1 500 to 6 000 hectares with a likely average of about 3 000 hectares. A smaller area would normally be affected with an open pit mine;

(b) the disturbance of local wildlife and vegetation by dusting from the construction and use of access roads, and the creation of unstable piles of waste rock or overburden;

(c) physical and/or chemical alteration of soils in mined areas through compaction by equipment and spills.

Wastewater discharges arise from dewatering of the mine area of runoff, disposal and groundwater releases into the mine pits, and direct run natural drainage systems from spoil piles. Some of the potential adverse impacts on the water environment as a result of coal-mining operation follows:

(a) alteration of natural surface drainage patterns resulting in uneven runoff with

---

* The factors which influence the number of hectares of land disturbed include the production rate, the ash content and heating value of the coal, and the thickness and depth of the seam in which the coal is found (the thicker the seam, the smaller the area disturbed).

potential for flooding and erosion;

(b) increase in sediments and dissolved metal levels in local streams making them unsuitable for irrigation, recreation, and other uses;

(c) disturbance of fish channelways and habitats;

(d) changes to groundwater systems due to dewatering of the mine area with possible adverse effects on soil quality, water quality, and availability of water.

Local air pollution can result from the generation of fugitive dust in excavating, loading, and stockpiling the coal, and the emission of methane gas from some underground mines.

iii) Mitigation Measures

The impacts from coal mining, although potentially severe, are of a local nature. Techniques exist which have proven effective in minimizing these impacts (19, 23, 43). Several such methods are:

(a) diverting streams around mine workings;

(b) building basins or lagoons to settle out suspended matter contained in wastewaters;

(c) monitoring and neutralizing wastewaters to precipitate out toxic heavy metals;

(d) reclaiming the land surface to a condition suitable for subsequent agricultural, recreational, or industrial-commercial-residential use.

Reclamation of strip-mined land may include: (i) selective placement of favourable overburden in spoil piles during the mining operation; (ii) smoothing out the spoil pile rows; (iii) raking and breaking up compacted surfaces; (iv) respreading stockpiled topsoil; (v) fertilizing and revegetating; and (vi) drainage control. Reclamation can usually proceed several rows behind the active cut so that only limited land areas are out of productive use at any one time (19).

Reclamation costs are highly variable depending on the topography, land area disturbed, and level of reclamation. Costs of reclaiming to wildlife habitat and cereal crop production for a new Canadian strip mining operation have been estimated (28) at $3 000 and $10 000 per hectare respectively. Costs in this range or even higher would add less than 2 per cent to the cost of generating electricity at a typical coal-fired station.

If mine operators practice judicious management techniques and carry out effective reclamation and rehabilitation programs, the most significant post-operational environmental concerns are those involving aesthetics. This is particularly true with respect to large worked-out open pits in the Rockies and foothills which are difficult if not impossible to backfill and reclaim. The prevention of future surface water pollution from acidity is possible with currently available technology. There are questions remaining, however, concerning the transmission of trace elements into groundwater systems by seepage from waste disposal sites.

2. Preparation

Presently four wet preparation plants are processing thermal coal in Canada. Two of these facilities are upgrading western bituminous coal for shipment to Ontario, and two in Atlantic Canada are cleaning local bituminous coal for use in nearby generating stations.

The preparation processes generally involve washing and gravity separation of the heavier non-combustible materials in the coal, followed by, in some cases, gas or coal-fired thermal drying. This coal preparation increases the heating value of the coal by reducing its ash content, and if pyrite is present, lowers its sulphur content prior to combustion.

The waste products consist of coarse and fine reject material (refuse) and wastewater. Coarse refuse is disposed of in an essentially dry state in surface piles or mined-out open pits. These piles can be sources of particulate laden runoff, seepage, and dust as well as being unsightly and potentially unstable. Due to the sulphur content of the coal, some of the

Maritime coarse refuse can generate acid, thereby contributing dissolved heavy metals to seepage or runoff water. Fine refuse is transported from the preparation plant as a reject/water slurry to tailings or "slurry" ponds where the solids settle out. These slurry ponds can occupy significant land areas and they can contribute particulate matter to the aquatic environment through runoff, seepage, and wind action. The effluents can also be acidic and contain dissolved heavy metals.

Emissions resulting from coal-fired thermal drying include particulates, sulphur and nitrous oxides, and various trace contaminants depending on the type of coal used as fuel.

Measures can be, and in most cases are, taken to minimize the adverse environmental effects of coal preparation facilities. Coarse refuse piles are commonly graded, compacted, and revegetated, and whenever possible runoff is collected and impounded to settle suspended matter prior to release to natural waters. The supernatant effluents from the fine refuse slurry ponds are recycl- ed to the preparation plants. Acidic waters that must be discharged can be first neutralized with lime to precipitate dissolved heavy metals.

The dry surfaces of inactive slurry ponds are commonly revegetated to reduce water and wind erosion and water infiltration, and to improve their appearance.

3. Transportation

In Canada, most long distance coal transport is by trains and ships, with short distance transport by truck. More than 80 per cent of Ontario's current thermal coal supply is received by ship from the United States. The transport of western thermal coal is primarily short haul from mine to power plant, but recent arrangements by Ontario to use coal from several coal mines in Western Canada are substantially increasing long distance rail haul with shipments to a new coal terminal at Thunder Bay.

The main sources of environmental damage during the transportation of coal are accidental spillage and windblown loss of coal. These losses can seriously affect both terrestrial and aquatic ecosystems along transport routes, and reduce the usefulness and habitability of the bordering land. When coal dust lands on vegetation it reduces the palatability of animal forage and retards growth by reducing photosynthesis. With truck transport, additional impacts result from dust generated by road construction activities and operation of the trucks. Some transport routes are dedicated to transportation of coal and their rights-of-way alone can occupy considerable areas of land, removing it from recreational, agricultural, or other uses.

The construction of coal stockpiling and transfer terminals has site-specific environmental impacts. If the site is near a body of water, as is the case at the Thunder Bay terminal, construction activities, coal spillage, dusting, and leaching from storage piles can cloud the water, deposit sediment, and contaminate surface and groundwaters with toxic substances. Accidental discharge of coal or fuel from ships can result in further aquatic impacts.

Methods to reduce windblown loss of coal from railroad cars include loading the cars so that the height and shape of the coal surface minimizes wind resistance, spraying binders which form a stable crust over the coal, and using covers.

Mitigative measures for truck transport also include the spraying of binders, use of covers, and layout of haulage routes and schedules which minimize adverse impacts.

4. Combustion (Power Generation)

i) Capacity and Operation of Coal-Fired Power Plants

There are currently 23 coal-fired electric generating stations in Canada with individual capacities ranging from 20 to 4 000 MWe. The four stations located in Ontario account for approximately 60 per cent of the current Canadian coal-fired generating capacity. The major increase in capacity during the next twenty years is expected to be in Alberta where several large new stations will be constructed.

The operation of a coal-fired generating station is shown schematically in Figure 4. Coal is fed into a boiler where it is burned under controlled conditions to produce heat. This

heat is used to generate steam which rotates a turbine and generator to produce electricity. After passing through the turbine, the steam is condensed back to water and returned to the boiler for reuse, thus completing what is known as the "steam cycle".

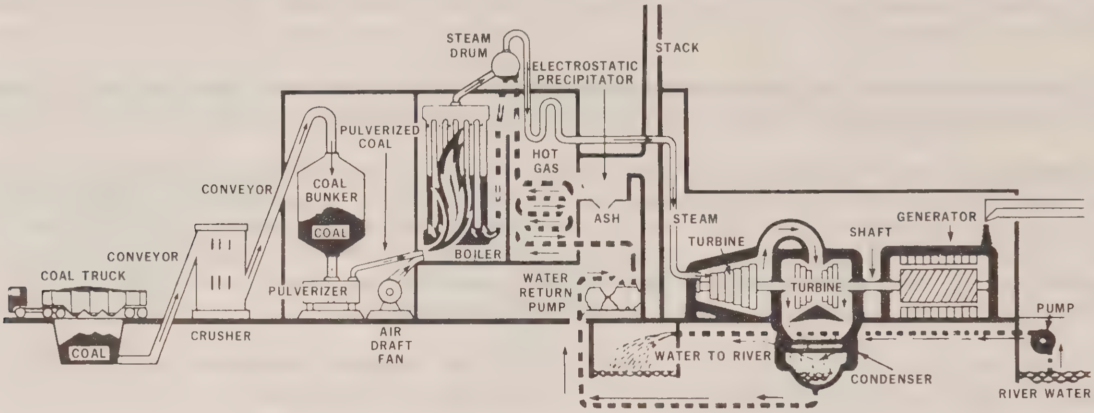


Figure 4 Typical Canadian Coal-Fired Generating Station

The pollutants released to the environment from the operation of coal-fired generating stations are associated primarily with fuel storage on-site, by-products of combustion (e.g. stack emissions and collected coal ash), and water used in operation of the steam cycle (e.g. boiler water and condenser cooling water).

ii) Local Environmental Impacts

Land Use

A typical coal-fired generating station requires that an area of several hundred hectares be removed from other land uses. If the station has a cooling pond and disposes of its ash into a lagoon, more than 1 000 hectares may be needed. Most of this land use is permanent (at least for the useful life of the station), unlike the temporary displacement in surface mining where continuous reclamation is possible.

Land use is normally considered in the choice of a plant site, and is addressed during public hearings and regulatory agency scrutiny.

Water Intake and Heated Discharges

Most Canadian power plants have once-through condenser (to condense steam) and auxiliary (to cool equipment) cooling systems. These systems withdraw large volumes of water from the source water body and subsequently discharge large quantities of heat to receiving waters, as illustrated in Figure 3. A 1 000 MWe station with once-through cooling will withdraw about 30 000 litres of water per second or about 2.6 million cubic metres per day, of which more than 95 per cent is used for cooling purposes. The same station would discharge to the receiving waters some 120 billion kilojoules per day of heat, or about 50 per cent of the heat value of the coal, with a typical temperature rise through the condenser of 10 to 15°C.

At stations with once-through condenser cooling, large numbers of aquatic organisms (plants, animals, fish, fish eggs, fish larvae) are often drawn in with the cooling water. The larger organisms can become trapped or impinged on the intake screens while the smaller organisms pass through the screens and, in many cases, are destroyed by mechanical damage in the pumps or heat shock in the condenser (30). Over the long term, this continuous loss of organisms can alter the aquatic community structure in the water body from which the station water is drawn, and in severe cases, lead to irreversible population decline of some species.

The thermal plumes from large power stations employing once-through condenser cooling can alter the natural temperature regime for several square kilometres in the receiving water body. This can lead to a change in fish species and populations in the discharge area, an increase in aquatic weed growth, disruption of fish spawning grounds and migration routes, and reduction of oxygen levels in the water. Fish may become trapped in lethal temperature water as

the plume shifts and impinges upon the bottom or shoreline, and fish residing in the plume can be killed by cold shock if the plant suddenly shuts down and the plume ceases to exist (13).

The severity of the aquatic impacts from heated discharges varies from one site to another depending upon many factors, including discharge temperature, heat dissipation rate, fish escape potential, type of discharge, and the fish species involved.

Consumptive Water Use

The condenser cooling system also contributes most of the consumptive water use (water not returned to source water body after use) at coal-fired generating stations through forced or induced evaporation. Water loss rates are typically about 0.3 litres per second per MWe for once-through cooling and about 0.6 litres per second per MWe for closed-cycle cooling (wet evaporative cooling towers or cooling ponds). A number of new coal-fired stations in western Canada will have cooling ponds.

The severity of high water consumption is highly dependent upon local availability of water and competing water uses.

Chemical Waste Discharges

Chemical waste discharges result from the need to dispose of water used for various processes in the station operation, and from runoff arising from rainfall on the station site. Even though less than five per cent of a station's total water intake is normally used for process or service water, this is a fraction of a very large intake volume and can produce substantial wastewater flows.

Wastewaters at coal-fired power plants originate from such sources as ash disposal system discharge, seepage from waste disposal areas, coal pile runoff, water treatment plant wastes, plant and yard drains, equipment cleaning wastewaters, boiler blowdown and blowdown from cooling towers or ponds (at stations with closed-cycle cooling). One of the largest wastewater streams at many stations is from direct release of the water used to transport coal ash from the station to a pond or lagoon.

Coal ash is now the tenth most abundant mineral in Canada with an annual production rate of about 3.7 million tonnes per year. The quantity of ash produced per MWe varies widely with the quality of the coal burned. Consequently, the total amount of water used to transport ash varies considerably from station to station. Table 1 illustrates this variation:

Table 1

Ash Transport Water Required for a 1 000 MWe Power Station

Coal Types	Ash Content %	Coal Consumption (Tonnes/year)	Ash Produced (Tonnes/Year)	Ash Sluice Water Required (m^3/Year)
Bituminous	10	1 980 000	198 000	3 900 000
Sub-bituminous	15	2 647 000	397 000	7 900 000
Lignite	30	3 957 000	1 187 000	23 500 000

Source: Adapted from Reference 4

Coal contains a large number of chemical elements, including radionuclides, many of which concentrate in the ash upon combustion. Certain portions of these trace elements are dissolved in the ash transport water and released to the environment with the direct discharge or seepage from the ash lagoon. Although the concentrations of trace elements in these wastewaters are usually low, large wastewater volumes can give rise to substantial total quantities being released to the environment over the lifespan of a station.

For example, even if there were only 0.5 milligrams of an element in one litre of wastewater discharged, the plant burning lignite in Table 1 would release 12 tonnes per year of the element

into the receiving water.

Chemical elements in coal ash which are of concern if released into the aquatic environment include the following:

arsenic	fluorine	mercury	thorium
barium	iron	nickel	uranium
boron	lead	phosphorus	vanadium
cadmium	lithium	radium	zinc
copper	manganese	selenium	

Those found to leach most readily from coal ash include arsenic, barium, boron, cadmium, chromium, copper, selenium, and zinc (5). Radium in fly ash has also been found to be more soluble than that in soil (22). There is little known at present about the leachability of the organic compounds of concern that have been found in some fly ashes. The leachability of all elements is highly dependent on the chemical composition of each ash type.

Because chemical wastewaters at coal-fired power plants are usually diluted by release into the large-volume cooling water discharge stream, the chronic long-term effects of large quantities of elements cumulating in the environment are a greater concern than immediate or acute toxicity. Trace metals and chemicals can build up in the receiving water over time, accumulating in sediments and bioaccumulating in aquatic plants and other animals in the food chain of fish. Certain aquatic species may concentrate a specific element by as much as 10 000 times over background water concentration (40). Elements commonly leached from coal ash such as arsenic, copper, selenium, and zinc may concentrate more than 1 000 times in some species of freshwater biota.

Aquatic effects of chemical wastewater discharges include increased turbidity which reduces light penetration, destruction of spawning areas and aquatic habitat from settling of solids, and synergistic effects between two or more chemicals. For example, even when their individual concentrations are low, cadmium, copper, and zinc react together to reduce the photosynthesis rate of freshwater plankton (40).

Seepage from ash and other waste disposal areas may contaminate groundwaters as well as contribute to surface water quality deterioration. Ash disposal areas at larger stations can occupy several hundred hectares making control of seepage difficult. Most soils have a capacity to adsorb certain of the trace metals that commonly occur in ash leachates. However, some may not be significantly adsorbed and will move through the soil with the seepage water. Further, the capacity of the soil to retain trace elements may eventually be exceeded causing contamination in the groundwater system to spread.

The United States Environmental Protection Agency is sufficiently concerned about the environmental contaminants in coal ash to seriously consider classifying it as a hazardous substance (41). If this action were taken, very stringent control measures would apply, including use of specially approved disposal sites. On the other hand, some States have classified coal ash as a mineral resource because of the metal recovery potential and other possible uses.

Current Canadian practices for coal ash disposal range from dry ash collection and disposal to once-through systems which pump a slurry mixture into a lagoon where the ash settles and water is returned to a local water course.

Deposition of Air Pollutants - Land and Water Impacts

During the combustion of coal, a portion of the chemical elements contained in the coal remains with the collected ash as discussed in the previous section. The remainder is released to the atmosphere via the stack either as part of the fine particulate matter emitted or as gases or vapours. In addition, numerous chemical compounds are formed during combustion and released.

Estimated quantities of basic pollutants now being emitted from coal- fired power generation in Canada are listed in Table 2.

Table 2

Basic Pollutants Emitted from Coal-Fired Power Stations in Canada

Substance	Quantity (tonnes/year)
Particulates	120 000
Oxides of Sulphur (SOx)	615 000
Oxides of Nitrogen (NOx)	144 000
Hydrocarbons (HC)	5 000
Carbon Dioxide (CO2)	73 000 000

Source: adapted from Reference 31

The quantities of particulates SOx and NOx in Table 2 are computed using emission rates determined for existing generating stations in Canada. The hydrocarbon estimate is based on an order of magnitude emission rate suggested by the U.S. Environmental Protection Agency (39), and the CO2 quantity is computed using approximate carbon contents (33,35,36) of the coals burned at Canadian power stations.

Examples of the kinds of chemical elements and compounds that are emitted from coal-fired power plants are listed in Table 3.

Table 3

Examples of Chemical Elements and Compounds Emitted from Coal-Fired Power Stations (17)

Class	Example of Species
Acids and Anhydrides	Nitric Acid
Amines	Nitrosamines
Inorganic Salts	Chromium Chloride
Carbonyl Compounds	Formaldehyde
Heterocyclics	Pyridines
Hydrocarbons	Benzene
Polycyclic Aromatic Hydrocarbons	Benzo-a-Pyrene
Sulphur Compounds	Hydrogen Sulphide
Organo Metallics	Tetraethyl Lead
Cyanides	Hydrogen Cyanide
Trace Elements - Toxic elements	Lead
- Radioactive elements	Radium

The released substances are dispersed into the atmosphere and deposited in a pattern dependent upon the stack height, emission rate, and prevailing atmospheric conditions. The areas of greatest annual deposition are often within 5 to 30 kilometres of the station, but portions of the emitted material are transported over hundreds of kilometres and deposited over a wide area.

In the immediate vicinity of the station (within 5 to 10 kilometres), deposition from fugitive dust emissions can far exceed the deposition from stack particulate emissions (19). Fugitive dust is wind-blown dust arising from coal storage piles, coal and ash handling operations, exposed surfaces in ash disposal areas, and the operation of equipment and other vehicles around the plant.

Local deposition of stack and fugitive dust emissions can affect both the terrestrial and aquatic ecosystems in the vicinity of the station. Particulates deposited on the leaves of plants can decrease photosynthesis and interfere with other leaf functions (40). Animal intake

of trace elements occurs via inhalation of particulates in the air as well as the ingestion of both surface and internally contaminated plants.

Acute injury to vegetation can be caused by high, short-term sulphur dioxide (SO_2) concentrations (40). Chronic and/or long-term effects of SO_2 on natural plant ecosystems include impairment of reproduction and germination which can cause long-term changes in plant productivity and community structure. These changes can, in turn, affect the animal components of the ecosystem via changes in habitat, food availability, and competition. These effects would be in addition to direct effects of SO_2 on animal species.

Direct deposition of particulates on soils can cause trace element enrichment in the upper soil layers followed by increased vegetation uptake, particularly in those areas near the power station in which maximum particulate deposition occurs. Increased concentrations of cadmium, iron, nickel, and zinc have been observed (40) in both the soils and vegetation near coal-fired generating stations. It has also been observed (22) that radionuclide concentrations (radium 226, thorium, and uranium) in vegetation in areas surrounding coal plants are higher than those in vegetation in agricultural areas.

Trace element enrichment in surface water systems can occur either from direct deposition of particulates on water surfaces or from runoff from the watershed areas where deposition on snowpacks, vegetation, or soils has occurred. In larger natural water systems, enrichment is not likely to be significant. However, in smaller headwater drainage systems some potential for trace element enrichment may exist, particularly in arid areas where containment reservoirs with low flow-through rates have been constructed.

iii) Regional Environmental Impacts

Formation of Acidic Precipitation

Some of the sulphur and nitrogen oxides emitted from coal-fired power plants are transported over long distances and have long residence times in the atmosphere. This permits the complex physical and chemical reactions necessary to transform these gases into acids to occur. These acids then fall to earth as acidic precipitation.

Terrestrial Impact

The long-term impact of acidic precipitation on soil fertility, agricultural crops, forests, and terrestrial wildlife is not yet completely known (37). It has been suggested that the deposits of sulphur and nitrogen could aid soil fertility in certain areas. On the other hand, acidification tends to demineralize soils and alter their rates of organic matter decomposition and nutrient recycling. Increased toxic metals solubility in water as a result of acidification also tends to increase their uptake and accumulation in plants.

There is a growing body of evidence indicating that crops such as beans, tomatoes, and apples can be directly damaged by acidic precipitation through damage to leaves and stems (37). Similarly, in addition to direct damage there is concern that the germination of seeds, the establishment of seedlings, growth, and the ability of forest trees and plants to combat disease and other organisms may be adversely affected by acidification.

Because the relationship between the plant/soil component and the wildlife of forest ecosystems is complex, the long-term impact of acidic precipitation is not clear. However, wildlife species populations are largely dependent on plant populations and inevitably, significant damage to plants will be reflected in the dependent wildlife populations.

Aquatic Impacts

The areas of Canada most sensitive to acidic precipitation are those in which there is little or no soil over the bedrock. Such bedrock tends to have a high silica content (i.e. granite) and be resistant to weathering. In these areas, there is insufficient buffering capacity on the land to neutralize the acidic precipitation before it runs off into the waterways. Since the lakes and streams in these areas also tend to have little buffering ability, gradual acidification of the natural waters begins to take place. As the waters become more acidic, trace metals which are found in bottom sediments and soils begin to dissolve and enter solution. Activity of decay organisms declines, and sensitive native fish species begin to disappear. In heavily impacted areas of this type, lakes may become essentially sterile within a few years.

Most of Canada except for the Prairie regions is sensitive to acidic precipitation. The majority of the major sulphur emitters (non-ferrous smelting, coal-fired power generation, and other industrial activities) and the most heavily loaded areas lie in the east. Figures 5a and 5b indicate the regions in eastern Canada in greatest peril.

Preliminary data indicate that SOx emissions from electricity generation in Canada are small (12%) relative to the contribution from non-ferrous smelters (45%). The contribution of electricity generation to NOx emissions is similarly small (10%) relative to the major source, which is transportation (62%) (32).

Canada tends to receive as much acid precipitation-causing substances from United States sources as it produces domestically. Although coal-fired power generation in Canada is a significant source in some sensitive regions, it is not the primary source of this country's problem.

iv) Global Environmental Impacts

Increasing levels of CO2 in the earth's atmosphere may lead to significant changes in climate on a global scale. The prime causes of CO2 increase in the atmosphere are the burning of fossil fuels, the removal and burning of forests, and decomposition of organic components of soils. Fossil fuel combustion is presently considered the major source of the increase, contributing from 3 to 10 times the amount resulting from deforestation, and adding almost 1 per cent annually to the CO2 in the atmosphere (42). CO2 production from the combustion of fossil fuels and the manufacture of cement has been increasing at a rate of over 4 per cent per annum. Among the fuels, coal produces about 75 per cent more CO2 than natural gas, and about 25 per cent more than oil for equivalent energy production (25,42).

In 1977 Canada consumed an estimated 32 million tonnes of coal, of which 21 million tonnes (66 per cent) was used for thermal purposes (34). This may be compared with estimates (25) of total coal production for the world in 1976 of 2 418 million tonnes which would indicate that Canada consumes less than 2 per cent of the world's coal production. This is also in line with the estimate that Canadian consumption of fossil fuels of all types accounted for about 2 per cent of the global CO2 production in 1974 (25).

The global CO2 cycle is not yet completely understood. However, current projections (2) are that the atmospheric concentration of CO2 will double the preindustrial level of 290 ppm before 2040. Models presently in use produce widely varying estimates of the global temperature changes which would result from such a doubling. The estimates range from negligible to almost 10°C and indicate an amplification effect in mid-to-high latitudes (18,29). However, a significant change in global mean temperature (2-3°C) from increased levels of CO2 would have major and relatively permanent effects, especially on agriculture, transportation, and the natural environment. The time lag (about 50 years) involved with the development and implementation of new energy technologies imparts some degree of urgency to the need for an improved understanding of the climatic impact of increased atmospheric CO2 levels.

v) Mitigation Measures

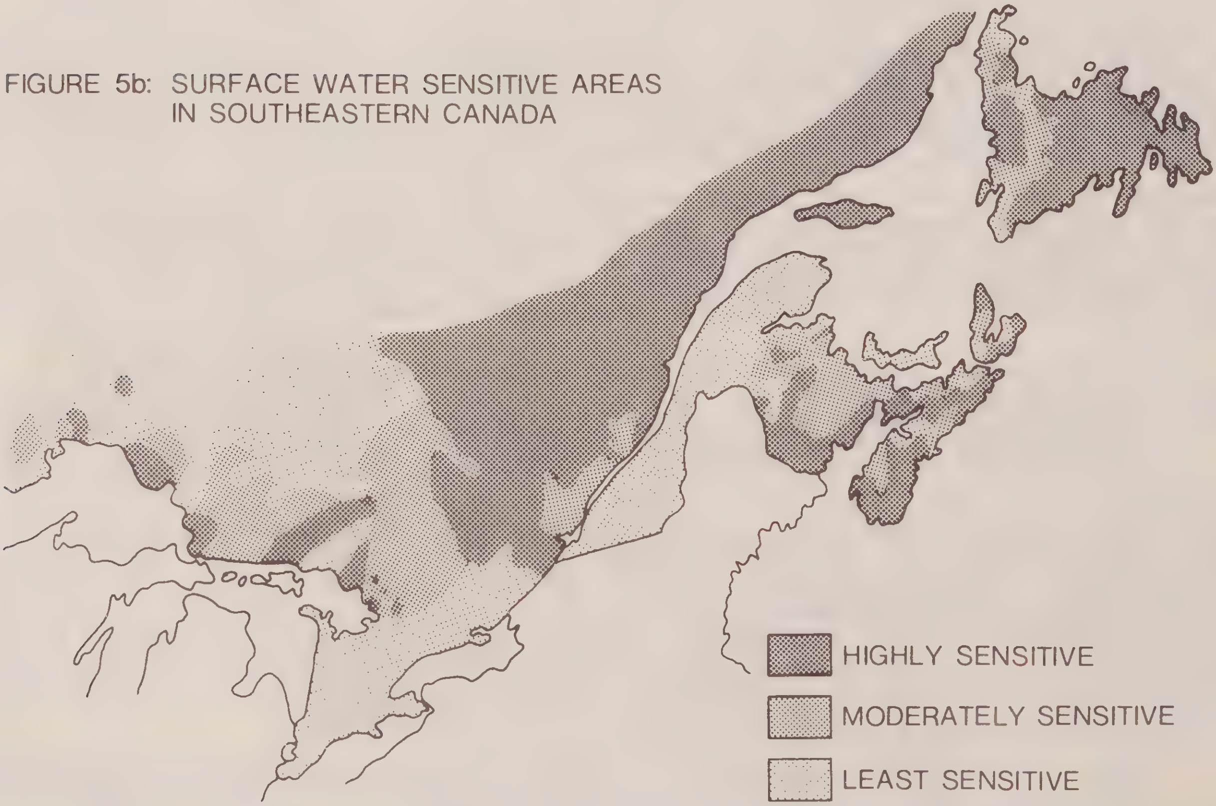
Control of Intake Water Volume and Heated Discharges

The technology to virtually eliminate the major aquatic concerns with the intake of large volumes of water for power plant cooling and the subsequent discharge of heated water is available and proven (38). Closed-cycle cooling in the form of recirculating cooling towers or cooling ponds reduces station water intake to a fraction of that required for once-through cooling. This minimizes both the intake of aquatic organisms and the discharge of heat to receiving waters. These systems will be used at planned new generating stations in Alberta and British Columbia, primarily because of inadequate water supply for once-through cooling. Such systems do, however, have some environmental disadvantages such as increased fogging, increased water consumption, increased energy consumption, need for chemical additives, and higher cost. Installation and operation of closed-cycle cooling will typically increase the cost of generating electricity at a coal-fired station by about 2 per cent (38).

Some of the environmental problems with large water volumes can also be minimized by less stringent means such as the use of fish bypass facilities at cooling water intakes, locating intakes and outfalls in areas of low biological activity, discharging offshore, and use

FIGURE 5a: NORTH AMERICAN AREAS CONTAINING LAKES THAT ARE SENSITIVE TO ACIDIFICATION BY ACID PRECIPITATION

FIGURE 5b: SURFACE WATER SENSITIVE AREAS IN SOUTHEASTERN CANADA



of outfall designs to achieve rapid mixing. Temperature rise across the station can be controlled to levels which will not kill entrained organisms and it may be possible in future to design pumps which will cause less mechanical damage to these organisms (30).

Control of Chemical Wastes

Substantial reduction in or elimination of the release of chemical wastewaters and leachates from coal-fired power plants can be achieved through the collection, containment, and treatment of the various wastewater streams, and the efficient reuse and recycle of waste streams. For example, the discharge of trace elements from ash disposal systems can be minimized either by using dry fly ash disposal or by recirculating the ash transport water in a wet disposal system.

Contamination of groundwater can be reduced or eliminated by locating ash and other waste material disposal sites on low permeability soils or by lining the disposal areas. However, large areas are often involved and seepage control can be difficult and costly.

Effective overall wastewater management systems can normally be implemented for less than 2 per cent of the cost of generating electricity. It is anticipated that all new stations will have effective wastewater control and chemical releases will not be a major environmental problem.

Control of Air Emissions

Several techniques are used to minimize the adverse effects of air emissions from the burning of coal. These can be grouped into distinct approaches, although some or all can be used simultaneously.

One method is simply to disperse the emissions generated over a large area, thus diluting the contaminants and reducing the severity of impact in the immediate vicinity of the plant. This is normally accomplished by erecting tall stacks. Although this technique may be partially effective locally, it passes on the bulk of the problem to someone else.

Another and more environmentally acceptable method is the installation of devices which remove the pollutants contained in the exhaust gases. The only such technology currently in use in Canada is particulate collection. The most common collectors are either cyclones, which are moderately efficient in removing relatively large particulates, or electro-static precipitators which are highly efficient devices removing up to 99.5 per cent of the particulates. The two devices are often installed in tandem (12,32). Fabric filter collectors (baghouses) are another option for high efficiency (greater than 99.8 per cent) particulate removal. Only one Canadian coal-fired station (Milner, Alberta) has experience with fabric filters to date. It is expected that all new plants in Canada will have high-efficiency particulate collection systems to minimize their particulate emissions. Even these systems, however, permit the very fine particles to escape.

Technologies are also available to substantially reduce SOx emissions from coal-fired stations. These include pre-combustion and post-combustion processes. The pre-combustion options include coal selection, coal blending, and coal beneficiation. Some utilities can readily obtain and burn only coals which have a low sulphur content, while others blend low and high sulphur coals to obtain a lower average. Although beneficiation is not widely practised on thermal coals in Canada, various mechanical coal cleaning processes are capable of removing a substantial portion (typically 30 to 40 per cent) of the sulphur prior to combustion. Chemical processes capable of removing up to 80 per cent of the sulphur are also under development. While coal cleaning processes may create waste disposal problems, as discussed earlier, these are readily controllable. If coal-fired drying is required, however, increased air emissions from coal-cleaning operations may be a significant concern.

The post-combustion processes for reducing SOx emissions consist of removing or scrubbing the SOx from the stack gases. Numerous flue gas desulfurization (FGD) processes are available which can remove more than 90 per cent of the sulphur from stack gases. These are either "throwaway" processes, in which large quantities of sludge are produced resulting in solid waste and wastewater control problems (4), or processes which regenerate or reuse the SOx absorbent and hence minimize the problems with solid waste and wastewater disposal. Although there are currently no FGD installations at coal-fired stations in Canada, several are in

commercial operation in other countries. At present the wet lime-limestone scrubbing throwaway processes are the most common.

The potential for installing FGD systems should be considered in any evaluation of the environmental and health effects of increased coal-fired power generation in Canada. The major deterrent to widespread application of FGD is its cost (31), which is typically 15 per cent or more of the cost of generating electricity. The increase in electricity rates attributable to FGD is highly dependent upon numerous factors such as sulphur content of the coal, emission control standards, and the capacity factor of the station.

Effective methods are also available to minimize fugitive dust emissions at power stations. These include dust suppression at active coal storage piles with water or chemical sprays, water sprays and mechanical containment devices for coal and dry ash handling, and revegetation of exposed dry ash surfaces in disposal areas preventing wind erosion.

5. Environmental Legislation

The responsibility for controlling impacts on terrestrial, aquatic, and atmospheric systems is shared between the federal and provincial governments. Under the British North America Act, the federal government has the primary authority to act in matters involving international affairs, issues of national or interprovincial concern, or imminent threats to health, navigation, fisheries, and migratory birds. The provincial government's authorities are largely derived from their responsibility for matters of property and civil rights.

At the federal level, pertinent legislation includes the Fisheries Act, the Environmental Contaminants Act, the Clean Air Act, and legislation relating to international affairs such as the Boundary Waters Treaty and the International River Improvements Act. While the situation is not identical in each province, the provinces have broad legislative powers to control the siting and operation of industry to meet environmental protection requirements.

Over the years various arrangements have been made between the two levels of government to meet their respective responsibilities in the most effective manner. In this regard, accords have been signed between the federal government and seven of the provinces which call for co-operative action in the protection and enhancement of environmental quality. A number of more specific arrangements are also in place; for example, the inland provinces administer the federal Fisheries Act.

Siting is a matter almost exclusively under provincial jurisdiction. Most provinces have requirements for an environmental assessment and review procedure before a large-scale coal activity is permitted. Control requirements are determined generally on a case-by-case basis. If the activity has the potential for affecting boundary or trans-boundary waters, then the federal government has a specific role to play in meeting its international obligations.

Most of the aquatic concerns (e.g. entrainment of aquatic organisms, discharge of heated waste water, leaching of trace chemicals into groundwater supplies, etc.) should be included in the provincial environmental assessment and review procedure. The federal government is likely to become involved only if the activity poses some threat to an area of specific federal jurisdiction such as fisheries or international affairs. In addition, the federal government is developing guidelines which recommend control limits on effluents from thermal power generating stations.

Most of the direct responsibility for air pollution concerns also lies with the provinces. Although specific requirements vary from province to province, their environmental protection acts generally provide the authority to deal with such local aspects as: limiting sulphur content of fuel, establishing ambient air quality objectives and opacity limits for visible stack emissions, and prescribing general operating conditions including operation limitations following specified air pollution episodes. The federal Clean Air Act complements and supplements provincial authority in this field. It specifically provides for the control of air pollutants which are hazardous to health, the control of air pollutants from federal facilities, and the control of the composition of fuels that are imported into Canada or involved in interprovincial trade. The Act also provides for the development, in co-operation with the provinces, of ambient air quality objectives based on three ranges (desirable,

acceptable, or tolerable) for each pollutant.

As part of its air pollution control the federal Department of the Environment has begun developing emission guidelines for specific industry sectors. The guidelines, while not legally enforceable, are viewed as the federal requirements for new sources and are aimed at avoiding environmental degradation. Guidelines for thermal power generating stations are under development.

Over the past several years increasing concern in both Canada and the United States about the problem of acidic precipitation has led both countries to express a strong interest in moving toward international arrangements to alleviate the impact. While the principal focus of attention in correcting the problem in Canada will be directed initially at the non-ferrous smelting industry, it is expected that attention will also be given to coal-fired thermal electric generation plants as coal use increases to meet energy needs in various parts of the country.

III: HEALTH AND SAFETY CONCERNS

1. Risk Assessment

Assessing the risk of adverse health effects from human exposure to polluting substances requires three steps:

(a) identifying the hazard;

(b) understanding the effect on human health of a given kind and degree of exposure (often referred to as the dose-response relationship);

(c) establishing the number of people exposed.

Risk analysis is generally conducted for the average individual. It is important, however, to recognize that different sub-groups in a population, for example children, pregnant women, elderly people, and people who are already ill, are often more sensitive to certain polluting substances than the average individual.

Two methods are commonly used to determine the health response to a dose of a substance: controlled experiments on laboratory animals, and the study of the causes of disease and deaths in groups of people known or suspected to have been exposed to the substance of interest (called an epidemiological study).
There are problems associated with both methods which make the estimation of risk uncertain at best.

For example, in both cases it may be difficult to attribute an effect to a specific substance in a complex mix of air pollutants. Determination of the exact exposure level with the potential to cause a health problem is complicated by variations in emission rates of a pollutant, weather patterns, and the geographic distribution of people around the pollution source.

In the case of epidemiological studies, it can be difficult to determine with confidence (in a statistical sense) that a particular kind of pollution is causing a certain number of excess deaths when the expected number of background deaths (against which excess deaths are compared) is very large.

Data used to estimate health and safety risks to workers at the workplace are based on observations of past experience (e.g., mining accidents or collisions between coal-carrying trains and automobiles at level crossings), and are usually more statistically certain than public health estimates.

2. Extraction (Mining)

The two major human health impacts from mining are fatal accidents and "black-lung disease" (coal worker's pneumoconiosis or CWP)*; both are hazards to the workforce, not the

---

* Other dust-inhalation diseases are a consequence of coal-mining, e.g., chronic bronchitis and emphysema, but CWP is the recognized disease for which compensation is paid.

general public. Estimates of accident fatalities per year per 1 000 MWe coal-fired plant are based on observed rates per million man-hours and average number of man-hours needed to supply fuel to meet the plant's annual requirements. They vary from 0.3 to 1.0 deaths per 1 000 MWe per year, with an average of about 0.4 (3,6,7,14,15,21,24,26). Estimates indicate that annual accident fatalities for underground mining are several orders of magnitude higher than for surface mining. Serious injuries in surface mining of coal were estimated to occur at rates ranging from 14 to 76 injuries per year per plant with a most likely range from 40 to 50 (3,6,7,26). Injury rates in surface mining again are substantially less frequent than those in underground mining.

There are two basic kinds of pneumoconiosis; the simpler form of the disease is seen 10 times more often than the more complicated and life-shortening form (14). Therefore CWP in surface mining is not considered a serious problem when compared to its occurrence in underground mines, or to workplace accidental injuries and fatalities in underground or surface mining.

With some 95 per cent of Canada's thermal coal being extracted by surface mining, concern with CWP is a localized problem specific to a few underground mines rather than a major concern associated with expanded thermal coal development nationally.

3. Transportation

The safety hazard in coal transportation affects both the general public and the transportation workforce, and exceeds the risk of accidental death in surface coal mining by three times or more (6,15,26). Estimates* in various studies of coal transportation accident hazards varied from 1.2 to 2.3 deaths per 1 000 MWe plant per year and from 0.33 to 23.4 serious injuries per plant per year (6,15,26). Most accidents happen when cars and trains collide at level crossings.

4. Combustion (Power Generation)

The estimates available for accidental death or serious injury to people working in the construction, operation, and maintenance jobs at coal-fired power stations range from 0.01 to 0.03 accidental deaths (6,24) and 1.38 serious injuries (6) per 1 000 MWe plant per year.

There are potential health effects associated with pollutants released at coal-fired power stations via both the air and water pathways. Trace elements or chemical compounds in wastewaters that are discharged to natural surface water or groundwater systems can make these waters unsafe for human consumption. Chemicals are also known to concentrate or bioaccumulate in aquatic food chains resulting in unsafe levels in fish species consumed by man. Fortunately, the technology to control wastewater releases from generating stations is available, and if effectively applied will minimize this area of concern. In addition, there is often an extra level of protection through drinking water standards and water treatment before consumption. Hence, the major health concerns with power generation are those associated with stack and fugitive dust emissions.

Stack emissions from coal-burning plants characteristically have four major types of impact on health: physiological irritation (sore eyes, nose, throat, itchy skin); direct toxicity; the causing of cancer; and the combination with other sources of stress to health (e.g. smoking) in such a way that the total health effect exceeds the expected effect from any single source of stress (synergism). The consequences of exposure to emissions from coal-fired plants will vary depending on the age and health status of the exposed individual, the nature of the harmful substance emitted, and the length of time the exposure lasts. The type of coal being used, the combustion process, and the efficiency of existing emission control devices will also influence the level of exposure to which people may be subjected. The health effects outlined below (40) are typical of those observed among persons exposed to airborne pollutants commonly found in emissions from coal combustion.

---

*The estimates were calculated assuming that coal travels along a 300 kilometres rail line to get to the typical plant in the U.S. Varying the distance travelled or the method of transport (ship and truck as well as train) to suit the Canadian experience would influence the estimates.

- Increased susceptibility to infection. Inflammation of lung tissue and general weakness produced by the toxic effects of air pollution makes the upper and lower respiratory tract more susceptible to infection. Exposed populations tend to suffer more cases of acute pulmonary diseases such as influenza, pneumonia, and colds; young children and the elderly tend to be the most susceptible groups.

- Irreversible damage to lung tissue. Experiments on animals exposed to long-term, low levels of common pollutants, and observations of people who smoke tobacco over a prolonged period of time have shown characteristic effects of chronic pulmonary injury such as emphysema and chronic bronchitis. It has been shown that when the respiratory tract has suffered early inflammation and subsequently certain kinds of irritant particles are encountered, that certain kinds of pneumoconiosis (silicosis, asbestosis, etc.) can develop. A person already in poor health from a condition such as chronic respiratory or cardiovascular disease, whether originally caused by the pollutants in question or not, is at much higher risk of suffering an acute or fatal episode when exposed to airborne irritants.*

- Cancer. Exposure to cancer-producing substances of the kinds commonly found in coal combustion products can lead to the formation of tumors or cancer in the tissue or organs where the carcinogen has been deposited. When these cancer producing substances move through the body and are transformed by the body, they have the potential to cause cancer in other organs as well.

- Damage to the lung from SO_2. SO_2 is one of the most studied components of air pollution (6,15,16,20,21,26,27). It has not been shown to produce serious direct effects in its pure state in humans at concentrations normally expected in areas of high coal utilization (0.3 to 1.5 ppm). However, levels above 0.25 ppm are usually associated with adverse health effects in epidemiological studies (40). People exposed to low levels of SO_2 over long periods of time have shown signs of a thickening of the protective mucus layer in the lung; this thickening reaction inhibits the removal of debris from the lung. Some studies have shown that SO_2 reacts with other irritants to either worsen or offset their effects.

- Particulates and synergisms** with adverse health effects. A significant portion of combustion products from coal is in the form of particulate matter. Because the size range of particles produced in coal combustion makes them easily breathable, a significant potential for adverse effects on human health is posed. Secondary particulates can be formed from post combustion interaction of gaseous products and sunlight; sulphates, nitrates, hydrocarbons, and photochemical smog are examples of products of reactions which occur in the atmosphere.

  The effects that particulate emissions can have on human health are determined by three factors:

  (a) the chemical composition of particles;

  (b) their size;

  (c) the amount of time they spend in contact with sensitive tissues.

  In general, smaller particles are more toxic than larger ones since they can reach the pulmonary region of the lung where they may remain for extended periods of times harming tissue. Many of the elements and compounds which escape in coal combustion become absorbed on the surface of particulates, thus magnifying the harmful effects on sensitive tissues. Several of the more harmful interactions which absorption by particulates permits include:

---

* Dramatic effects of air pollution on health were observed as a result of temperature inversions in Donora, Pennsylvania (1948) and in London, England (1952).

** A synergism is defined as an interaction among substances in which the total effect of the interaction exceeds the sum of the effects of each substance.

(a) the transformation of SO_2 to more potent irritants such as sulphur trioxide, sulphate* ion and sulphuric acid;

(b) a variety of carcinogens may be carried by particulate matter;

(c) a variety of trace metals (lead, mercury, arsenic, nickel) which are highly toxic may be carried by particulates. These substances tend to be deposited and retained in the body's cells and affect the central nervous system and organ systems other than the respiratory system.

- Organic emissions of concern to health. The organic nature of coal provides the potential for formation of a wide variety of organic emissions especially during short-lived generating conditions which result in incomplete combustion. The complexity of these mixtures makes it virtually impossible, in field studies, to identify a single chemical entity as the causative agent in human disease. However, under experimental conditions a number of organic combustion products have been identified as "known" or "suspected" carcinogens, others as strong eye and lung irritants (40). Several of these substances are explained below:

(a) The most serious potential for causing cancer comes from a group of compounds known as "polycyclic aromatic hydrocarbons" (PAH). The most widely studied chemical in this group, "benzo-a-pyrene" has clearly been shown to be a causative factor in skin and lung cancers in experimental animals (40);

(b) Formaldehyde and acrolein are hydrocarbon irritants. Their initial effects at concentrations of a few ppm or less are tears or sneezing, inflamation of the nasal passages, coughing, sore throat, and tightness in the chest;

(c) Contaminants which can be considered as secondary products of coal combustion arise from interactions between effluents and ultra- violet radiation. Examples are ozone and peroxyacylnitrates (PANS), the latter group comprising particularly potent irritants;

(d) Nitrogen oxides are formed by oxidation of organically bound nitrogen in secondary atmospheric reactions. Long-term exposure of experimental animals to low levels of NO_2 (0.5 ppm) resulted in irreversible emphysema-like lesions on the lungs. As with SO_2 humans appear to be able to build up a tolerance to the effects of acute inflammation. Such a mechanism, however, may not exist for effects other than inflammation;

(e) Carbon monoxide (CO) is produced during the incomplete combustion of coal. When inhaled at sufficiently high concentrations, CO inhibits the oxygen carrying capacity of the blood. People with cardiovascular diseases who are exposed to elevated levels of CO will experience increased frequency and duration of their symptoms and excess deaths may occur.

- Public health effects-quantitative estimates. Estimates of fatalities from coal combustion by-products varied from 327 per million exposed people per year** from SO_2 and total suspended particulates (TSP) (21), to 0.018 deaths per million exposed people per year.*** Based on an assumption that 3.8 million people lived within 80 km of a typical 1 000 MWe coal-fired power plant with a 1 000 foot stack, excess deaths per year were estimated to range from 0.067 to 1243 (16).

---

* Sulphates in the presence of particulates have been recognized as particularly harmful in several epidemiological stuides (15,16,20,21,26).

** Assuming low sulphur coal with no controls, or high sulphur coal with removal of 75 per cent of SO_2 from stack gas.

*** Varied sulphur and TSP control from 90 to 99 per cent for various sulphur-content coals.

5. Summary of Health and Safety Risks from All Stages of the Coal Trajectory

In order to compare overall health risks from the use of coal-fired or nuclear generating stations, it is necessary to sum all of the estimates of these risks which can reasonably be made. Table 4 summarizes the estimates of serious illnesses, injuries and premature deaths from coal-fired generation of electricity for each stage of the coal fuel trajectory.

It should be noted that the range of estimated values varies relatively little for some health effects (1.67 times for occupational accidents and illnesses during combustion) and enormously for others (more than 18 000 times for excess public deaths from combustion by-products). The estimates with smaller ranges of variation tend to be associated with activities and events (accidents etc.) which have a reasonable statistical base from observation of past operations (e.g. mine safety). The wide range of estimates of public health effects (deaths and disease) from the combustion of coal to generate electricity reflects a number of limitations and uncertainties in the data about and understanding of these effects. Genetic effects have not been included due to the limitations of current knowledge about them. The data do not adequately discriminate between premature deaths early in life, which greatly shorten life, and premature deaths of the elderly, which may shorten life by relatively little Lack of knowledge about the quantity and type of pollution substance and the size of its effect on human health makes the upper estimates of the effects unreliable. The generalization has been made, however, that the economic impact of the non-lethal effects of coal-fired utility air emissions is probably much greater than that of premature deaths (27).

These estimates were generated from assumptions about conditions in the United States (excepting references 3 and 13 on mining safety); they cannot be directly applied to the Canadian experience, nor can extrapolations be made from them without making allowance for several differences, some of which are included in the following list:

(a) population distribution and size in Canada in relation to pollution sources probably differs from that used in the many estimates;

(b) the level of pollution control efficiency which will be practiced at new generating plants will probably differ;

(c) the expected range of load factors at coal-fired plants in Canada and the U.S. has not been specified and will differ between the countries. For example, Canadian fossil-fueled plants tend to be run at higher load factors during the winter when air masses are more stable, allowing for greater dispersion of stack emissions; U.S. plants are generally run at higher load factors in the summer.

(d) all Canadian stations presently have stacks much lower than the 1 000 foot height assumed in the emission dispersion models;

(e) most of the planned expansion of coal-fired generating stations will take place in Alberta where population density is much lower than that assumed in the U.S. models;

(f) the majority of newer Canadian coal-fired generating stations already have particulate removal efficiencies in excess of 90 per cent, and all future stations are likely to have removal efficiencies greater than 99 per cent;

(g) the background of environmental insults that a typical Canadian population is exposed to may not be similar to that assumed in the U.S. study.

IV: SUMMARY OF MAJOR ENVIRONMENTAL HEALTH AND SAFETY CONCERNS

The generation of electrical power using coal as fuel involves recognizable and, to a degree, measurable risks to the environment and to human health. Assessment of these risks is necessary not only to decide what degree of safety and pollution control measures society should invest in at different stages in the coal trajectory, but also to plan for the most economic and lowest risk mix of generation methods.

Table 4
Annual Health and Safety Effects of Operating a
1 000 MWe Coal-Fired Power Plant*

Stage in Fuel Trajectory	Serious Illnesses and Injuries	Premature Deaths (accidents and disease)
Occupational		
Extraction	14.0 - 97.0	0 - 3.5
Transport	0.33 - 23.0	0.055 - 0.4
Combustion	0.9 - 1.5	0.01 - 0.03
Sub-total	15.0 - 122.0	0.065 - 4.2
General Public		
Extraction	Not detectable	Not detectable
Transport	NA**	0.55 - 1.9
Combustion	160.0 - 320.0***	0.067 - 1 243.0
Sub-total	160.0 - 320.0	0.62 - 1 245.0
Total Occupational and Public	175.0 - 442.0	0.7 - 1 250.0

* Values given are lowest and highest estimates from references (3,6,7,14,15,16,17,20,21,24,26, 27).

** The figures for occupational transportation injuries include those for the general public; the latter could not be separated out.

***Due to measurement difficulties, numerical estimates for non-fatal disease due to this source of air pollution are very uncertain. Induced cases of respiratory disease probably exceed estimated fatalities by several times (27).

According to the foregoing analysis, the predominant impacts of using coal as fuel for power generation are as follows:

(a) Environmentally, there are several major issues. These include:

- disturbance of land in surface mining;

- land requirements for cooling ponds, ash and sludge disposal, and transportation routes;

- the mobilization of chemical elements in the coal and their release to the local environment from various sources (coal preparation, ash disposal, stack emissions);

- loss of aquatic populations due to destruction of organisms in the large water volumes used by power plants;

- alteration to aquatic systems by the discharge of heated effluents by power plants;

- water consumption by power plants in arid areas;

- damage to lakes, forests, and crops from acidic precipitation

All of these with the exception of land temporarily disturbed in surface mining and the permanent land requirements of power stations and transportation routes are avoidable or controllable at some economic cost.

(b) In human health, the effect of airborne combustion products is the major issue. Despite the great variations in some of the risk estimates, damage to human health from air emissions is likely to be appreciable. It is, however, largely controllable at some economic cost.

In summary, the environmental and health impacts of coal-fired power generation can be substantial. However, application of available pollution control technology at each stage of the coal trajectory will minimize many of the major impacts and strengthen the position of coal as a major alternative for the production of electrical energy in Canada.

1. Alysworth, J.A. Coal, Canadian Mineral Survey, 1979. Ottawa, Energy, Mines and Resources Canada, 1980.

2. Bacastow, R.B., and C.D. Keeling. Models to Predict Future Atmospheric CO2. In: Workshop on the Global Effects of Carbon Dioxide from Fossil Fuels. W.P. Elliot, ed. Miami Beach, Florida, March 7-11, 1977. pp. 72-90.

3. Brooks, D., and B. Berry. Mine and Health Safety as an Analytic Problem. Ottawa, Energy, Mines and Resources Canada, 1972. (Mineral Bulletin MR-125)

4. CH2M Hill Canada Limited. A Quantitative Comparison of Water Intake, Wastewater Production, Wastewater Treatment and Other Costs Associated with Air Pollution Control Devices for Coal-Fired Steam-Electric Power Generating Stations. Ottawa, Environment Canada, 1979. (EPS3-WP-80-1)

5. Chu, T.J., and R.J. Ruane, "Characterization and Reuse of Ash Pond Effluents in Coal-Fired Power Plants, Tennessee Valley Authority". Journal of the Water Pollution Control Federation 50: 2494-2508, November, 1978.

6. United States. Council on Environmental Quality. Energy and the Environment - Electric Power. Washington, D.C., 1973.

7. Dials, G.E., and E.C. Moore. "The Cost of Coal - We Can Afford to Do Better". Environment 16:18-37, September, 1974.

8. Edmonton Power Co. Application to the Energy Resources Conservation Board for Approval to Construct, Connect and Operate the Genessee Power Plant and Mine, Environmental Impact Assessment. Edmonton, 1977.

9. Canada. Energy, Mines and Resources Canada. 1976 Assessment of Canada's Coal Resources and Reserves. Ottawa, 1977. (Report EP-77-5)

10. Canada. Energy, Mines and Resources Canada. Coal Mines in Canada, January 1978. Ottawa, 1979. (Operators List 4)

11. Canada. Energy, Mines and Resources Canada. Electric Power in Canada - 1979. Presented to the Canadian Electrical Association, Spring 1980. Ottawa, 1980.

12. Canada. Environment Canada. Air Pollution Emissions and Control Technology: Thermal Power Generation Industry. Volume II - Particulate Emissions. (Report No. EPS-3-AP-79-6) (To be published in 1980)

13. James F. Maclaren Limited. Heated Discharge Control and Management Alternatives: Small Water Bodies and Rivers. Ottawa, Environment Canada, 1977. (EPS Report 3-WP-77-13)

14. Gibbs, G.W., and P. Pintus. Health and Safety in the Canadian Mining Industry. Kingston, Ontario, Queen's University, 1978.

15. Hamilton, L.D., and S.C. Morris. Health Effects of Fossil Fuel Plants. Upton, N.Y., Brookhaven National Laboratories, 1974.

16. Hamilton, L.D. Energy and Health - The Health Impacts of Present and Alternative Energy Sources and Policies. Upton, N.Y., Brookhaven National Laboratories, 1975.

17. Heit, Merrill A. A Review of Current Information on Some Biological and Health Related Aspects of the Release of Trace Metals into the Environment Associated with the Combustion of Coal. Washington, D.C., U.S. Energy Resource Development Agency, 1977. (Report No. HASL-320)

18. Idso, S.B. "The Climatological Significance of a Doubling of Earth's Atmospheric Carbon Dioxide Concentration". Science 207:2060-2066, March, 1980.

19. International Joint Commission. International Poplar River Water Quality Study. Appendix E: Plant, Mine and Reservoir Operations. Windsor, 1979.

20. Lave, L.B., and E.P. Seskin. "Air Pollution and Human Health". Science 169:723-733, August 21, 1970.

21. Lave, L.B. "Health Effects of Electricity Generation from Coal, Oil and Nuclear Fuel". In: Energy and the Environment - A Risk Benefit Approach. Ed. by H. Ashley, R.L. Rudman, and C. Whipple. Oxford, Pergammon Press, 1976. Pp. 63-87.

22. McBride, J.P., et al. "Radiological Impact of Airborne Effluents of Coal and Nuclear Plants." Science 202:1045-50, December 8, 1978.

23. Nephew, E.A. "Healing Wounds". Environment 14:12-21, January/February, 1972.

24. Ramsay, W. Unpaid Costs of Electrical Energy - Health and Environmental Impacts from Coal and Nuclear Power. Baltimore, Johns Hopkins University Press, 1979. (Resources for the Future)

25. Rotty, R.M. Present and Future Production of CO_2 from Fossil Fuels - A Global Appraisal. In: Workshop on the Global Effects of Carbon Dioxide from Fossil Fuels. Ed. W.P. Elliott. Miami Beach, Florida, March 7-11, 1977. pp. 72-90.

26. Sagan, L.A. "Health Costs Associated with the Mining, Transport and Combustion of Coal in the Steam-Electric Industry". Nature 205:107-111, July 12, 1974.

27. Sagan, L.A., and C.L. Comar. "Health Effects of Energy Production and Conversion". Annual Review of Energy 1:581-600, 1976.

28. Saskatchewan Power Corporation. Poplar River Thermal Power Project, Environmental Assessment and Mine Reclamation. Summary Report. Regina, 1977.

29. Schneider, S.H. "On the Carbon Dioxide-Climate Confusion". Journal of Atmospheric Science 32:2060-2066, November, 1975.

30. Schubell and Marcy (eds.). Power Plant Entrainment: A Biological Assessment. New York, Academic Press Inc., 1978.

31. Shawinigan/Intergroup. Air Emission Control Options: Canadian Utility Cost Impacts. Montreal, Canadian Electrical Association, 1979.

32. Shawinigan/Intergroup. Economic Impact of the Proposed Federal Emission Guidelines. Montreal, Canadian Electrical Association, 1979.

33. Shawinigan Engineering Western Ltd. Combustion of Canadian Coal and Lignite in Generating Station Boilers. Montreal, Canadian Electrical Association, 1978.

34. Canada. Statistics Canada. Canada Year Book. Ottawa, 1978.

35. Tibbetts, T.E. Evaluation of Canadian Commercial Coals: Saskatchewan, Alberta and British Columbia - 1975. Ottawa, Energy, Mines and Resources Canada, 1976. (CANMET Report 76-41).

36. Tibbetts, T.E., and W.J. Montgomery. Evaluation of Canadian Commercial Coals: Nova Scotia and New Brunswick - 1975. Ottawa, Energy, Mines and Resources Canada, 1976. (CANMET Report 76-40).

37. United States-Canada Research Consultation Group on the Long-Range Transport of Air Pollutants. U.S. Co-Chairman: A.P. Attshuller, Canadian Co-Chairman: G.A. McBean. The

LRTAP Problem in North America: A Preliminary Overview. Washington, D.C., and Toronto, Ont., 1979.

38. U.S. Environmental Protection Agency. Development Document for Effluent Limitation Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C., 1974.

39. U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. 2nd Ed. Research Triangle Park, N.C., 1973.

40. U.S. Nuclear Regulatory Commission. The Environmental Effects of Using Coal for Generating Electricity. Washington, D.C., 1977.

41. Weismantel, G.E. "Ash - A Thorny Problem in Coal Utilization". Chemical Engineering 87:72-74, January 28, 1980.

42. Wilson, C.L. Coal-Bridge of the Future. Report of the World Coal Study. Cambridge, Mass., Ballinger Pub. Co., 1980.

43. Zurkowski, I. "Strip Mining of Coal". In: The Environmental Price of Energy. Ed. by A.J. Van Tassel. Lexington, Mass. Lexington Books, 1975. Pp. 223-265.

ENVIRONMENTAL AND HEALTH ASPECTS OF THE NUCLEAR FUEL CYCLE

This paper is based on a draft prepared by Dr. H.C. Rothschild, Nuclear Programs Division, Environmental Protection Service, Environment Canada.*
November, 1980

* now with the Office of Environmental Affairs, EMR

Foreword

The following review is aimed at outlining the major issues of concern relative to the environmental and health effects of nuclear power. In such reviews, it is often desirable to strike a balance between simplification, which enhances comprehension, and technical detail which is aimed at achieving scientific accuracy. This balance is not always easily attained, especially in a field such as this where a variety of issues need to be presented within a scientific background that encompasses a number of disciplines - physics, chemistry, biology, medicine, engineering, public health, etc. In addition, the health and environmental risks from nuclear power are often perceived from different sets of values regarding things nuclear, these values resulting in preconceived notions that may affect the perception as much as does the scientific data base. There is, therefore, another balancing act that is called for - that of presenting the issues from a neutral viewpoint. There are no presumptions about the desirability or undesirability of nuclear power but rather an attempt to present as objectively as possible an analysis of the environmental and health consequences of selecting nuclear power.

Contents

INTRODUCTION

The concern about the dangers of nuclear power is rooted in the perception of radiation as hazardous to people and the environment. There exists the fear of a possible sudden, unforeseen release of large quantities of radioactive materials such as could occur in the event of an accident at a nuclear power plant, and that this release might cause immediate death and destruction and render areas uninhabitable. There is also the worry that the steady release from nuclear facilities of controlled amounts of radioactivity will, over many years, alter the character of the environment and harm human populations.

EFFECTS OF RADIATION

Radiation and Radioactivity

An atom, the smallest entity that distinguishes individual elements of all matter, comprises two major components: a positively charged nucleus and a surrounding cloud of negatively charged electrons. Each element is characterized by a specific atomic structure.

Radioactive atoms, or radionuclides, have unstable nuclei in which changes towards a more stable condition result in the release of sub-atomic units (particles or energy) from the nucleus. These releases constitute nuclear radiation, often called ionizing radiation because of its effect on matter. The nuclear transformation that radionuclides undergo in becoming more stable is called decay. Each type of radionuclide decays at a characteristic and constant rate, measured as the time required for one-half of the atoms to decay. This time is referred to as the 'half-life 'of a radionuclide.

The principal forms of nuclear radiation of significance to living systems are alpha particles, beta particles, gamma rays, and neutrons. Alpha particles are emitted only by elements of high atomic weight, such as radium. They are identical to the nuclei of helium atoms, consisting of two neutrons and two protons, and have an atomic mass of four. Because of their relatively large mass and positive charge, alpha particles travel short distances. In air, for example, they travel between 0.2 and 10 centimeters, depending upon the energy with which they are released. The outer layer of the human skin is thick enough to absorb, virtually harmlessly, all alpha particles. Alpha-emitting radionuclides pose a potential hazard only when they are deposited internally.

Beta particles can be either positively charged or, as more often, encountered with those radionuclides associated with nuclear power, negatively charged. They are only 1/7 400 the mass of alphas and travel much farther in air and other media, with a much more variable range than that of alpha particles. They are relatively easily absorbed and, for external irradiation, are of concern only to superficial tissues of living systems. When deposited internally, they are of much greater concern.

Gamma radiation is part of the electromagnetic spectrum and, as such, is similar to visible light and ultra-violet radiation. It is, however, much more energetic and highly penetrating. Gamma radiation consists of photons and has no electric charge or significant mass. Though sources of gamma rays are of less concern than those of alphas or betas when deposited internally, they constitute greater concern with regard to external irradiation.

Neutrons are electrically neutral and have an atomic mass of one. While they cause ionization only indirectly, their interaction with matter usually results in effects similar to those of alpha and beta particles, and gamma rays. The range of neutrons depends upon their energy, but for radiation protection purposes they are generally considered to be about as penetrating as gamma radiation.

Interaction of Radiation with Matter

When nuclear radiation interacts with living or other matter, it loses its energy by colliding with the atoms or nuclei of the molecules in the material. As a result, some of the molecules become damaged by a disruption of the chemical bonds holding them together or by a

loss of electrons. This loss of electrons is called ionization and is the reason for identifying alphas, betas, and gammas as ionizing radiation. The amount of ionization produced in matter by the energy loss of the radiation along its path is referred to as the Linear Energy Transfer (LET). The higher the LET, the greater the concentration of energy deposition in a tissue and also the greater the biological effect. Alpha particles and neutrons have the highest LET, followed by betas and then gamma rays.

The unit used to express the absorbed energy, or dose, from radiation is the rad. However, because the concentration of energy deposition is so important in determining biological effect, another unit, the rem, is usually preferred. The rem is described as a unit of "dose equivalence" because it puts into equivalent terms the biological significance of different kinds of radiation. One rad from alpha radiation equals 20 rem, one rad from neutrons equals 10 rem, and one rad of beta or gamma equals one rem. The biological effect is also determined by the rate at which a dose is received. The relation between biological effect and dose rate is a complex one, but in general, the higher the rate, the greater the effect.

Evaluation of Radiation Effects

Very high doses of radiation to humans - those that exceed 150 rem delivered in a short period of time - usually result in immediate effects, such as skin lesions, cataracts of the eye, and destruction of cells, including blood-forming tissue. Acute doses above 250 rem could lead to death. These effects, often called "non-stochastic", are characterized by a threshold dose below which the effects are not encountered. Furthermore, the severity of the effect is generally proportional to the dose received.

At lower doses and dose rates the effects, if any, appear some time after the dose has been received and are thus termed late or delayed effects. They result from the interference of the radiation with the biological information that cells transmit to their "offspring" during the natural process of cell division. When this interference leads to cancer or leukaemia in the exposed individual, it is named a delayed "somatic effect". When it occurs among the reproductive cells and causes an hereditary defect in some member of a later generation, it is called a "genetic" effect.

Most individuals in a population exposed to low levels of radiation will suffer no effect, but a small fraction might develop cancer or pass on genetic damage to their descendants. It is not possible to predict which individuals will be affected; so to reflect the statistical nature of the possible effects, the late effects of radiation are termed "stochastic". The late effects are therefore expressed as the percentage of a certain exposed population that might show the effect for a given dose equally distributed to that population. For example, one estimate is that if one million people were each exposed to one rem of radiation, between 15 and 25 of them would be expected to develop leukaemia in 8 to 13 years. Factors other than radiation exposure, including exposure to carcinogens such as tobacco smoke and various other toxic chemicals, appear to make some individuals more susceptible than others.

The late somatic effects of radiation are not unique in that the cancers and leukaemia induced by radiation cannot be identified as being caused by the radiation. In fact, the consequence of low level radiation exposure is a small increase in the normal incidence of particular diseases such as cancer or leukaemia. It is not possible, at low doses, to differentiate between those cases attributable to radiation exposure and those attributable to other causes.

Estimates of genetic risk are not based on epidemiological studies of irradiated human populations because such studies have failed to reveal any increase (directly or indirectly) in the frequency of hereditary diseases as a result of radiation exposure. While data on the natural prevalence of hereditary diseases in man are of some use, estimates of genetic risk rest mainly on observations of radiation effects in laboratory mammals such as mice.

Risk estimates for stochastic effects in life systems other than human are difficult to quantify for many reasons. The aquatic and terrestrial flora and fauna consist of a series of ecosystems. In each ecosystem a number of plants, wildlife, aquatic, and microbiological species live fully interdependent lives. It is postulated that damage to one of the species that constitutes a key component in the ecosystem could lead to disruption of the system. The

study of radio-ecology is made more difficult by this interdependency, the great number of species, the variety of food chains, and the variety of environmental settings.

When dealing with biota other than humans, the risks are at the level of the population rather than the individual. Important somatic effects, from a population viewpoint, include the loss of several individuals in the population, or a general shortening of lifespan of enough individuals in the population to cause a decrease in reproductive capacity. The genetic effect of concern is a buildup of deleterious mutations which may lead to a shift in selective pressure and/or a decrease in overall fitness of the population. Although there are a great deal of data on the genetic effects of radiation on biota, the prediction of the effects on populations is hampered by a less thorough understanding of the somatic effects on individuals of different species, and of the mechanisms by which different organisms regulate their numbers. Although it has often been suggested that man is one of the most radiosensitive species, this thesis is difficult to prove since data on somatic risks for species other than man are insufficient. However, as populations and the ecosystems they form are subject to many natural stresses and yet remain stable, it is reasonable to assume that effects from radiation will only be significant when they are comparable to other stresses encountered.

Cancers and genetic defects are both believed to be associated with changes in DNA, a complex molecule which is the carrier of hereditary information for all living organisms. The consequences of radiation damage to DNA have been studied in a wide variety of living organisms. An indication of the relative importance of this factor in different species is provided by Table 1. It will be noted that a given level of radiaton exposure, e.g. the natural background level of 0.1 rem per year, is responsible for only a small fraction of the total genetic defects which occur spontaneously in all living organisms and that this fraction becomes increasingly smaller for organisms with a shorter generation time than humans.

The levels of radionuclides released to the air or water during the normal operation of nuclear facilities are orders of magnitude lower than those found to affect most living organisms. Therefore there does not appear to be much risk involved with normal operations. The movement of radionuclides through biological pathways is, however, dependent upon many factors and some combination of ambient water and air quality conditions could conceivably lead to enhanced concentrations of radionuclides in organs of certain species. Many measurements of dilution and of concentration of radionuclides in food chains leading to humans have been carried out and estimations of radiation doses to humans always include an assessment of the effects of the radionuclides which reach humans through biological pathways.

Table 1

GENETIC CHANGES INDUCED BY NATURAL BACKGROUND RADIATION LEVELS (0.1 REM PER YEAR) IN DIFFERENT LIVING ORGANISMS

Organism	Approximate Generation Time	Average Percentage of Observed Spontaneous Genetic changes that are Caused by 0.1 rem per year
Yeast (s. cerevisiae)	2 hours	0.000001
Wasp (Dahlbominus)	2 weeks	0.01
Mouse	4 months	0.05
Human	30 years	3.0

THE CANDU FUEL CYCLE

The generation of electricity by nuclear power involves a series of activities that begin with the mining of uranium ore (see Figure 1). The mining and milling process consists of crushing and grinding the rocks taken from the mines and of adding either an acid or an alkaline leaching material to dissolve the uranium and separate it from the other materials. The product from the mill is either ammonium or magnesium diuranate, both of which are referred to as yellowcake.

The radionuclides of interest in uranium mining and milling result from the radioactive decay of uranium. Those of most biological significance are radium-226 and radon-222, a decay product of the radium. Radium is a natural component of uranium ore and is separated from uranium in the milling process along with other wastes. It ends up in the mine and mill tailings piles from which it can be leached into ground water systems. Radium-226, which has a half-life of 1 600 years, emits alpha radiation, making it potentially hazardous if taken into the body by inhalation of dust or by ingestion. It is of concern when introduced into the aquatic ecosystem, because it then can be transmitted to humans through fish or drinking water. Radium is chemically similar to calcium and thus is incorporated into the skeleton, where its slow turnover rate and proximity to blood-forming organs combine to make its alpha emissions particularly hazardous.

Radon-222 is a radioactive gas produced by the decay of radium-226. The release of radon from the earth's surface is a natural phenomenon and varies with geology, climate, soil composition, and season. During the mining process, the release of radon is enhanced when the rock is broken. Workers in underground mines are exposed to radon and its "daughters" (radioactive products of radon decay) through inhalation and receive a radiation dose to the lungs. The mining/milling operations can also lead to small increases in the ambient concentration of radon in the air around the site due to escape from the tailings piles, particularly if they are in a dry state. This would increase slightly the radiation dose to the general population in the area.

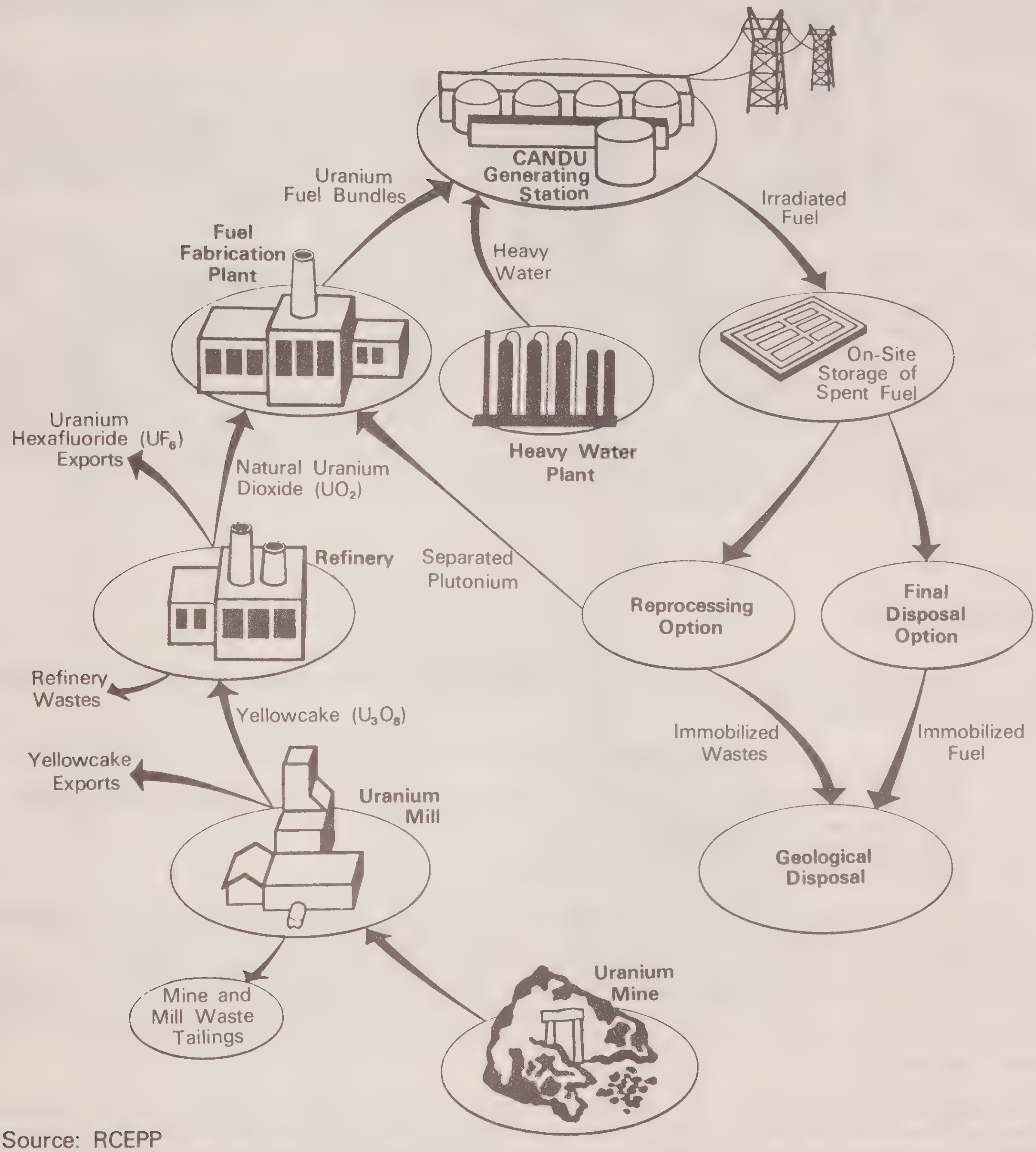
The yellowcake intended for use in Canada is reduced to uranium dioxide in the uranium refinery and then sent, in powder form, to a fuel fabrication plant. That destined for export, which accounts for 80 per cent of the uranium now processed in Canada, is converted to uranium hexafluoride, a chemical amenable to uranium enrichment. Although refinery workers are exposed to uranium-bearing dust and to radon, the health and environmental concerns of uranium refining are related as much to non-radioactive chemicals as to radioactivity.

The use of heavy water is one of the features that characterizes the CANDU reactor, which uses the liquid in its cooling and moderating systems. The production of heavy water involves the use of hydrogen sulphide gas and releases pollutants such as sulphur dioxide and hydrogen sulphide.

A schematic of the CANDU nuclear reactor is shown in Figure 2. The power plant can be seen as having two major components: the "nuclear furnace", where the energy from controlled fission of uranium-235 atoms heats the heavy water in the primary loop; and the steam raising system, where high pressure and temperature steam in the secondary loop is converted into electric power. When the uranium atoms in the fuel undergo fission, they produce heat and fission products (smaller atoms resulting from the breakup of uranium) and neutrons. The neutrons can react in one of two ways. They can be "captured" by other uranium-235 atoms and continue the fission process, or they can be caught by other atoms and produce "activation products" which are generally radioactive. One of these activation products is plutonium-239, which is fissionable; another is tritium, formed by neutron activation of the deuterium in heavy water.

The fission products, such as strontium-90 and cesium-137, and plutonium produced by the fission process, are contained in the ceramic matrix of the fuel pellets, which are in turn contained in zirconium alloy sheaths. Some of the plutonium contributes to the fission process and will therefore be burned up as it is created. Certain fission products, notably iodine-131, xenon-133 and xenon-135, are more volatile than others, and if there are any defects in the zirconium fuel sheaths, a fraction of them might be released to the primary coolant system during normal reactor operation.

Figure 1: **Once-Through CANDU Fuel Cycle**



Source: RCEPP

Fuel rods are assembled in bundles and these contribute to efficient reactor operations for specified periods of time after which they are removed and replaced with fresh bundles. The "spent fuel" still contains some uranium-235, some useful plutonium-239, other activation products of uranium-238 called trans-uranics, fission products, and most of the initial uranium-238. It is very radioactive and is kept at the reactor site in engineered structures called spent fuel storage bays, which resemble large swimming pools. The water in the storage bays shields the radiation from those working in the general vicinity of the bays and carries away the heat created by the radioactivity (radiation is a form of energy and when absorbed by matter becomes heat).

Some countries such as France and the United Kingdom "reprocess" the fuel, but in Canada there are, at present, no plans to carry out reprocessing, i.e. to extract from the spent fuel the remaining uranium or, of greater potential use, the plutonium-239. Regardless of whether reprocessing is used, there will be high-level radioactive wastes that must be disposed of permanently. If no reprocessing is done, the spent fuel will have to be disposed of; if reprocessing is done, then the reprocessed wastes will have to be disposed of.

Canadian plans for disposal of high-level radioactive wastes are to use deep burial in a geologic medium that will offer isolation and shielding and that is expected to remain stable for many milleniums into the future. The plan is to excavate a cavity similar to an underground mine in a large, stable rock formation. After the wastes have been immobilized and placed in containers resistant to leaching and corrosion, they would be placed in the cavity and back-fill would be inserted. The selection of useable sites would involve consideration of the movement of groundwater and the remote possibility that over a long period of time small amounts of radioactivity might be leached into the groundwater system. The site would eventually be decommissioned, so that future generations would not be burdened with responsibility for further management or monitoring. Further information on this is given in "Radioactive Waste Management and Disposal".

RADIOLOGICAL IMPACT

The radiological impact on man and the environment from the nuclear industry is determined by the following analytical steps:

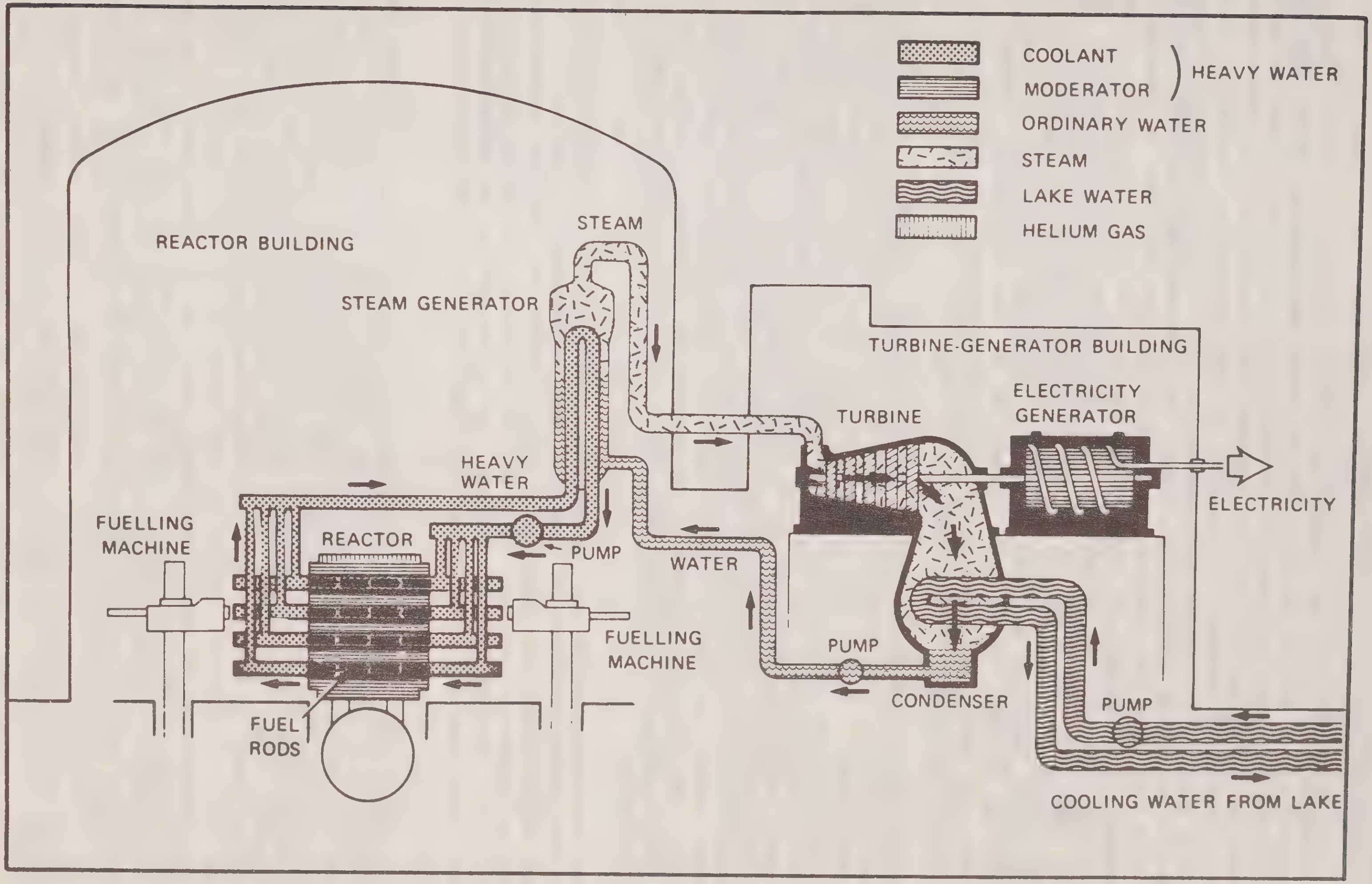
1) measure or estimate the amount and type of radioactive materials released into the environment;
2) evaluate the movement of these materials, especially the pathways both short and long-term to human populations;
3) calculate the dose to the population;
4) estimate the risk from the absorbed dose.

Step 1 can be made for routine operations by continuously monitoring all the effluents from a nuclear facility and checking the results with measurements of the radioactivity in the surrounding area. Steps 2 and 3 are also straightforward procedures involving no major differences of opinion among scientists, although more information on pathways would be useful. But step 4, which calls for the estimate of the hazards associated with the doses calculated in step 3, has caused controversy because of the debate over the effects of low doses of radiation.

It has not been possible to measure directly the stochastic effects of low levels of radiation because they are so small, spread out over time, and cannot be distinguished from naturally occurring effects. They can only be estimated from the observed effects of high doses. It is the method of estimation, however, that has caused some publicized and apparent disagreement among scientists. In recent years there have been several detailed reviews of this question by learned groups, and most have concluded that the methods of estimation used probably overestimate the risks associated with low doses of radiation.

Most scientists agree that, in the absence of direct evidence, it should be assumed that all radiation, no matter how small the dose, has the potential of causing damage, even though

Figure 2: The CANDU Nuclear Generating Station



Source: AECL

no experiment can be devised which is sensitive enough to demonstrate the presence or absence of an effect at the very lowest doses. Scientists also believe that rejection of the threshold concept is prudent, since the lack of experimental evidence cannot absolutely rule out the possibility of some sort of effect over the long term.

Another assumption is that the number of effects (cancers or other diseases) will be directly proportional to the total dose and that this relationship holds true down to zero dose. This connection, which is described as linear, is theoretical. Much of the controversy on the effects of low levels of radiation stems from the use of this relationship. While there is some laboratory evidence to support it, epidemiological studies on exposed human populations are subject to various interpretations and are too inexact to demonstrate the nature of the relationship down to zero dose. The argument has been made that there is a possibility that low doses of radiation are relatively more efficient in causing cancer than are high doses. No proponent of this view, however, has yet presented a reasoned case convincing to the majority of scientists. On the other hand, the various national and international committees appointed to review biological radiation (i.e. the International Commission on Radiological Protection, the United Nations Scientific Committee on the Effects of Atomic Radiation, the U.S. National Council on Radiation Protection and Measurements, and the U.S. National Academy of Sciences Committee on the Biological Effects of Ionizing Radiation) have all agreed that the linear dose-response model is most likely to represent that upper limit of potential hazard caused by low levels of beta, gamma or X-radiation.

Everything on earth, including humans, is continuously exposed to low levels of radiation from two natural sources: the radioactive materials inside our bodies and around us, and the radiation from space. There also exists in the world large quantities of naturally radioactive materials and these are found throughout the oceans, in the earth's crust, and indeed in all living things. In this broad context, the environmental impact of adding a relatively small amount of radioactivity to this inventory by using nuclear power can be regarded as insignificant. This fact alone, however, does not ensure that the effects of this added radioactivity will be unimportant. Any increase in radiation levels might cause some damage, however slight, to people's health and could conceivably have other effects on animal and plant life. The sensible approach is to control all releases of radioactivity to ensure that the local changes in background are kept as low as feasible and that the long-term effects are minimized.

The above considerations of the impact of the nuclear industry assume the adherence of the industry to the present standards of operation and to permissible radioactive releases. The Atomic Energy Control Board has established release limits for Canadian nuclear reactors based on an operating target of one per cent of the allowable radiation doses to the general public. There is a growing concern, however, about the effects of an accident at a nuclear station which could result in the release of radioactivity in amounts greatly above those limits.

As in all hazard situations, the seriousness of potential nuclear accidents is a product of the probability of the accident and the effects if it does occur. Predictably, the estimation of both probability and effect sparks controversy. On the question of probability, critics point to the recent accident at the Three Mile Island reactor in Pennsylvania, in which human error played an important role in the series of mishaps that led to the accident. Nuclear proponents argue that this same incident demonstrated that the "defence-in-depth" system actually worked by controlling a condition caused by a serious set of malfunctions so that no lives were lost and the exposure of the public was a small fraction of the regulatory limits. (The calculations of population doses, based on the measurement of radioactivity in the environment around Three Mile Island, lead to an estimate of less than one delayed cancer fatality for the entire exposed population.) Risks similar to those posed by the U.S. type reactors also exist with the CANDU reactor, although the probabilities and consequences of accidents at CANDU plants differ in detail.

In assessing the impacts from a nuclear accident, the following points are noteworthy:

(1) The fatalities resulting from stochastic effects, which occur many years after the dose has been received, would greatly exceed the immediate fatalities due to exposure to high levels of radiation. Estimates range from 30 to several hundred times more

stochastic than non-stochastic effects depending upon factors such as the distribution of the affected population.

(2) The major part of the dose to populations during an accidental release would be an external gamma dose from radioactivity in the air and on the ground. The contribution later from environmental pathways and food chains would be usually much smaller.

ENVIRONMENTAL QUALITY STANDARDS

National and international organizations have established guidelines for maximum permissible concentrations of radioactivity in the environment and for maximum permissible doses. The standards set by regulations in Canada are described in "Safety in the Nuclear Fuel Cycle". The radioactivity levels specified under the Canada-U.S.A. Water Quality Agreement for the Great Lakes (1978) provide an example of an international standard:

> "The level of radioactivity in waters outside of any defined source control area should not result in a TED_{50} (total equivalent dose integrated over 50 years as calculated in accordance with the method established by the International Commission on Radiological Protection) greater than 1 millirem to the whole body from a daily ingestion of 2.2 litres of lake water for one year. For dose commitments between 1 and 5 millirem at the periphery of the source control area, source investigation and corrective action are recommended if releases are not as low as reasonably achievable. For dose commitments greater than 5 millirem, the responsible regulatory authorities shall determine appropriate corrective action".

An increase in radiation exposure of 1 mrem represents about 1 per cent of the natural level of radiation to which man and other organisms have been exposed for millions of years. This quantity is considerably less than the normal variation in natural levels caused by differences in altitude and local geology.

NON-RADIOACTIVE EFFECTS

Although the public concerns related to nuclear power are focused on radiation, there are other, more conventional environmental and health effects associated with nuclear energy. These impacts are typical of any large-scale industrial activity and include heavy metal and acid leaching from uranium mine tailings, the release of hydrogen fluoride from uranium refineries, the release of hydrogen sulfide gas from heavy water plants, the release of large volumes of heated water from nuclear reactors, and land requirements for all facilities in the nuclear fuel cycle. Some of these effects, such as those resulting from heavy metal and acid leaching, from land requirements, and from the release of heated water, are also encountered with other fuel cycles such as coal.

The major effect on land use of the nuclear fuel cycle occurs in the mining and milling operations, although the loss of prime agricultural land where most nuclear facilities are sited is also a concern. The amount of land needed for mining, milling, and tailings management depends largely on the nature of the ore body, the mining and milling processes, and the management method used for the tailings. To produce a given amount of energy, smaller quantities of materials are mined and processed for the uranium fuel cycle than for fossil fuels, because there is more energy released per weight of uranium than per weight of fuel converted to energy by combustion (a chemical reaction). The other principal land use commitment occurs at the reactor site, with the requirement of large areas for the reactor building and exclusion zone. Rights-of-way for the high-voltage transmission lines are characteristic of all electricity generating options.

All heat-producing energy options have some thermal effects. About two-thirds of the energy produced cannot be used to generate electricity and must be rejected into the environment. Because nuclear generating stations are slightly less efficient than comparable non-nuclear ones, more waste heat is discharged from nuclear reactors than from fossil fuel power plants of similar capacity.

The regional or local effects of thermal effluents vary, of course, with the particular site and locale. In Canada, the impact of thermal discharges can be considered to be potentially beneficial during the colder months. However, some scientists are concerned about the local increased "thermal loading" on a specific body of water. Whether the net impact is beneficial or detrimental, ecological changes will result. Some of those changes can be minimized by using some of the waste heat for space heating or horticulture. Both of these applications have been used in other countries with industrial and environmental benefits and are now starting to be introduced.

SUMMARY

Concern about nuclear power is rooted in a fear of radiation. It focuses on the possible effects on man and the environment from steady releases of controlled, low levels of radioactivity and from the possible release of large amounts of radioactivity in an accident.

Radiation effects are of two major types. At high doses, they show up soon after the dose is received, with the severity of the effect being proportional to the total dose. At low doses, the effects occur many years after irradiation and can either be somatic or genetic. For both somatic and genetic effects, the probability of risk is assumed to be directly proportional to the dose and to be without a threshold.

Each step in the CANDU fuel cycle can lead to exposure of individuals to radiation and other hazards. The areas of most concern particularly as perceived by the public are in connection with nuclear reactor accidents and the disposal of radioactive wastes. Reactor accidents have the potential for the release of large amounts of radioactivity. Feasibility of safe concepts for disposal of radioactive wastes over thousands of years is being studied, but assessment of their reliability will not be completed for some time.

BIBLIOGRAPHY

1. Aikin, A.M., et al. The Management of Canada's Nuclear Wastes. Ottawa, Energy, Mines & Resources Canada. 1977. (Report EP-77-6)

2. Basuk, J., and A. Nichols, An Overview of the Ionizing Radiation Hazard in Canada. Report prepared for the Policies and Poisons Committee. Ottawa, Science Council of Canada, 1979.

3. Great Britain. Royal Commission on Environmental Pollution. Chairman: Sir Brian Flowers. Nuclear Power and the Environment. London, 1976.

4. International Commission on Radiological Protection. Problems Involved in Developing an Index of Harm. London, Pergammon Pr., 1977. (Number 27)

5. International Commission on Radiological Protection. Radionuclide Release into the Environment: Assessment of Doses to Man. London, Pergammon Pr., 1979. (Number 29)

6. International Commission on Radiological Protection. Recommendations. London, Pergammon Pr., 1977. (Number 26)

7. Newcombe, H.B. Public Health Aspects of Radiation. Chalk River, Ont., Atomic Energy of Canada Ltd., 1978. (AECL 6330)

8. Nuclear Energy Policy Study Group. Nuclear Power: Issues and Choices. (Ford-Mitre Report) Cambridge, Mass., Ballinger, 1977.

9. Ontario. Environmental Assessment Board. The Expansion of the Uranium Mines in the Elliot Lake Area. Final Report. Toronto, 1979.

10. Royal Commission on Electric Power Planning. Chairman: Arthur Porter. A Race Against Time; Interim Report on Nuclear Power in Ontario. Toronto, 1978.

11. Royal Commission on the Health and Safety of Workers in Mines. Commissioner: James M. Ham. Report. Toronto, 1976.

12. Saskatchewan. Cluff Lake Board of Inquiry. Chairman: Justice E.D. Bayda. Final Report. Regina, 1978.

13. United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR). Sources and Effects of Ionizing Radiation. New York, 1977.

14. U.S. Interagency Task Force on the Health Effects of Ionizing Radiation. Report. Washington, D.C., Dept. of Health, Environment and Welfare, 1979.

15. U.S. National Academy of Sciences. Risks Associated with Nuclear Power: A Critical Review of the Literature. Washington, D.C., 1979.

RISK ASSESSMENT AND REGULATION

Department of Energy, Mines and Resources

November, 1980

TABLE OF CONTENTS

Generating electricity from any source involves some risks for both those in industry and in the general public(17, 19). In the case of nuclear power, the main concern is radiation, the effects of which have been described in "Environmental and Health Aspects of the Nuclear Fuel Cycle". Concerns are for both the immediate effects of high-level exposure and for long-term exposure at high and low levels (such as cancers and genetic effects).

The purpose here is to discuss the concept of risk, examine its application in the assessment of effects of radiation, describe how regulatory bodies like the Atomic Energy Control Board (AECB) in Canada determine acceptable levels of risk, and compare radiation risks with risks from other activities. More briefly, it attempts to describe how regulatory authorities answer the question "how safe is safe?".

THE CONCEPT OF RISK

Risk can be defined as the frequency of an event happening multiplied by its consequences. One common way to express this calculation is as the expected number of harmful effects in a group of exposed people; this kind of calculation expresses risk to society. In simple notation:

Risk	=	Frequency	x	Magnitude
or,		or,		or,
consequences per unit of time		number of events per unit of time		consequences per event

Risk is also frequently expressed in terms of the average individual's chances of being harmed by an event, that is, the risk to any particular person within society. Risk estimates are commonly expressed as risk per unit of time (usually a year). A sample calculation of individual risk of natural background radiation-induced fatal cancers would be:

$$\frac{200 \text{ deaths}^*}{\text{year}} \div 20\,000\,000 \text{ persons}^* = \frac{0.00001 \text{ deaths}}{\text{person-year}}$$

In other words, the average Canadian, each year, has a chance of 1 in 100 000 of dying from cancer from natural sources of radiation.

This definition indicates that it is possible for a frequent event that causes few deaths per occurrence to have the same statistical risk as a rare event that has large consequences each time it happens. This does not mean, however, that as a society we can be expected to, or that we should, accept these identical statistical risks as being of equal significance. It may well be that people worry more about very rare events which have disastrous consequences for many people than they do about more frequent and routine events which affect relatively few people each time they occur, even if the statistical risks of each event (measured in terms of expected disease, injury or fatality) are the same. For example, the risks associated with airplane travel are accepted, although a crash that kills 100 people is headline news and leads to investigations and possible actions to prevent its recurrence. In contrast, because single events are less dramatic, the deaths per year of thousands of individuals in automobile accidents are accepted with little apparent fuss.

The evaluation of comparable statistical risks can also be complicated by the degree of freedom which individuals perceive themselves to have in their decisions to assume these risks. It has been shown that individuals will accept large risks if they have some degree of control over their engagement in the risk-causing activity. Thus, an individual may face far greater health risks riding in a car than from living at the boundary of a nuclear reactor site, while still preferring that more of society's resources be devoted to reducing risks from nuclear power generation than to improving auto safety.

---

* On average, 200 persons in Canada out of a population of slightly more than 2 million are expected to die from cancer caused by exposure to average natural background radiation.

These realities - different attitudes towards events of equal statistical risk - pose some difficult problems for risk assessment and regulation. One problem is in determining what people's preferences actually are, and how they are expressed. Measurement of people's feelings about the risks of various activities which convey a number of benefits can be very difficult: it is impossible to find a universally accepted decision-making rule by examining people's behaviour as consumers, voters, or as respondents to surveys. This uncertainty extends to the choice of a method to allocate funds for safety among activities. A simple criterion would be the increasing of expenditures for those activities which have the greatest statistical risk of harm. Another measure could be the achievement of the maximum reduction in statistical risk for the minimum cost, a kind of cost-effectiveness test(15). However, these methods do not necessarily reflect society's judgement of how best to allocate funds for risk reduction, i.e., what is the social value of extra statistical safety. Despite the uncertainties involved in risk assessment, safety standards are set, and the following sections outline how this is done.

1. THE ESTABLISHMENT OF ACCEPTABLE RADIATION CRITERIA

i) The Effects of Ionizing Radiation

Ionizing radiation is defined as electromagnetic and particulate radiation. As it is absorbed by living tissue it can split molecules into charged particles or ions, thereby causing changes in some biochemical activities. Somatic effects (those which show up in the tissue of the body) and genetic effects (those transmitted to offspring) can result from these changes.

The degree of damage depends on the amount, rate, type, and energy of the absorbed radiation. Radiation dose is measured in "rems", which is the absorbed dose taking into account biological factors. A millirem is one-thousandth of a rem.

The larger the radiation dose, i.e., the more energy deposited, the greater the biological damage. If the dose is big enough, the effects are immediately observable and are called non-stochastic (certain to happen) and definite. Examples of non-stochastic effects range from cataract induction in the lens of the eye to radiation sickness. For acute doses over 250 rem, death might occur within a short period. It is generally accepted that non-stochastic effects of clinical significance appear only above a threshold dose of about 25 rem. Below this dose, non-stochastic effects are not observable.

The numerical estimates of the effects of low doses of radiation are indefinite and reflect random events which are determined by the laws of statistical probability (they are stochastic); such effects become observable after a period of latency. The delay between a small radiation dose and observable somatic or genetic effects can be several years or generations. For a given population it is expected that a certain number of people will suffer adverse effects, but the particular individuals cannot be identified in advance. The stochastic effects of concern are cancer and genetic damage. Cancer can develop over a period during which a cell is made malignant by the action of radiation. Genetic damage can result from mutations due to irradiation of the germ cells of individuals who contribute to the gene pool and shows up as increased hereditary disease and birth defects. However, ionizing radiation only increases the frequency of naturally-occurring mutations and cancers; it does not cause new or different ones.

It is generally accepted that for doses in the middle range (25-250 rem) the relationship between the stochastic effects and the absorbed dose is roughly linear. That is, the number of effects is directly proportional to the total dose. At doses below 10 rem, effects are so few that they are difficult to measure with statistical accuracy, since their natural incidence from many other sources obscures any increase. Nevertheless, the projection of a linear extrapolation to zero dose between absorbed dose and effect in tissue has been adopted to estimate these effects. It should be emphasized, though, that this is an estimation based upon assumptions that will probably never be proven by statistical manipulation. The adoption of a linear response assumes that damage to the living cell is not repaired, that the dose rate does not matter, and that the effects are cumulative over time. This approach is generally regarded as conservative.

ii) Risks from Radiation

When referring to the consequences of collective exposure of the general public or industry workforce to ionizing radiation (from accidental or routine releases), risk is usually expressed as the number of cases of cancer which are expected to appear over the lifetime of a million exposed people. In the case of routine radiation exposures, the probability of the radiation release is one; that is, it is certain. The risk of the exposed population is considered statistical because, while the identity of the people who will contract cancer at some point in their lives is unknown, it is certain that some will. Thus, in the case of doses to humans of ionizing radiation, a somatic risk of 200×10^{-6} fatal cancers per man-rem means that if one million people were exposed to an average dose of one rem each during some period, 200 of them (0.02%) would be expected to die from cancer sometime in their lives due to this exposure.

The effects of ionizing radiation on human populations have been well documented in epidemiological studies of selected population groups who are known to have received significant radiation doses, e.g., the survivors of Hiroshima, the Marshall Islanders, uranium miners, radium-dial painters, radiologists, and patients treated with X-rays. The dose-response relationships for both somatic (long-term) and genetic effects have been thoroughly reviewed by three committees: the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR)(1), the International Commission on Radiological Protection (ICRP)(2), and the United States National Academy of Sciences Advisory Committee on the Biological Effects of Ionizing Radiation (BEIR)(3).

These committees' estimates of total risk and of risk to various organs and tissues, which are based on the assumption of proportionality and with no threshold for low-level radiation effects, are given in Table 1.

The various estimates are not significantly different in a statistical sense. Total cancer deaths per man-rem received per million persons for whole body exposure range from 100 to 200. Estimates have also been derived for leukemia and for cancers of the bone and of the breast, lung, thyroid, and other organs. For example, the risk of induction of fatal thyroid cancer of 5×10^{-6} (see the ICRP figure on page 14, Table 2) implies an incidence of 5 cases per man-rem received per million people. The argument can be extended to predict that if one million people receive one rem to their thyroid for each year for 50 years, $5 \times 50 = 250$ of them would be expected to die of thyroid cancer at some point in their lifetime.

Table 1

Estimates of Integrated Lifetime Risk

Organ or Tissue	BEIR (3)	ICRP (2)	UNSCEAR (1)
	(Somatic - fatalities per man-rem x 10^{-6})		
Whole Body	200	100	100
Red Bone Marrow	40	20	20
Bone		5	4
Lung	40	20	25
Breast	40	25 *	50 **
Thyroid	1	5	10
Stomach, Liver, Intestine	40		
Other	40	50	40
Genetic Effects +	60-1 500	200	200
++	25-600	80	80

* Risk to entire population
** Risk to females only
\+ From genetically significant radiation exposure (dose received by age 30).
++ From radiation exposure over a life-time.

The estimates of genetic risk of all three organizations give a risk of a clinically significant genetic change per man-rem of about 200 x 10^{-6} over all generations descending from the exposed population. Estimates of the genetic risks of radiation are largely derived from studies on mice and fruit flies, and have been extensively reviewed in the 1977 UNSCEAR Report(1). The kinds of genetic changes being referred to include: single gene mutations which show up as congenital cataract, cystic fibrosis, some forms of muscular dystrophy, colour blindness, hemophilia; chromosomal aberrations which may result in spontaneous abortion or Down's syndrome (mongolism); and complexly-inherited diseases from many heredity-determining origins such as cleft palate, skeletal anomalies (both are birth defects), and, later in life, heart disorders, epilepsy, asthma, diabetes, and schizophrenia.

iii) Establishing Regulations

Once the risks from radiation are estimated as accurately as possible, the next step is to determine the level of risk that should be set for the regulation of the nuclear industry and for all other users or producers of ionizing radiation. This is the central issue to be addressed. The question has been the main focus for many decades for the ICRP, an independent body established by the International Congress of Radiology in 1928. This non-governmental body works closely with UNSCEAR, the International Atomic Energy Agency (IAEA), and the United Nations World Health Organization (WHO). The members of the ICRP are chosen because of their scientific expertise and reputation. While the recommendations of the ICRP and its committees lack statutory force, they have served as the basis for technical regulations and codes of practice in many countries.

iv) Assumptions Behind 'Acceptability'

The ICRP has recommended maximum 'acceptable' dose levels both for nuclear industry workers and for individuals in the population at large. Since there is no recognized 'safe' threshold radiation exposure level below which no somatic or genetic response is expected, criteria other than 'no-effect' must be introduced to set standards for permissible health effects. The ICRP has recommended that the average occupational dose of radiation be low enough that the risk of death from that exposure be no greater than the risk of death in 'safe' industries (shoe, garment, communication)(6). The chance of a fatal accident in a safe, non-nuclear industry has been estimated at 1 in 10 000 per year (1 x 10^{-4} per year); the average occupational radiation exposure producing an equivalent statistical health hazard is 1.4 rem per year. The ICRP has found that, by setting the maximum permissible dose to the most exposed member of the nuclear workforce at five rem per year, average radiation exposures are achieved which make statistical risk of death in nuclear and safe industries equivalent.*

The maximum annual dose for individuals in the general public has been recommended by the ICRP not to exceed 0.5 rem or 500 millirem a year (one tenth of the maximum permissible occupational exposure). The different standards reflect several factors: (i) that higher doses for shorter periods of time are equivalent in expected health effects to lower doses for an uninterrupted, long period of time (public exposure over a lifetime); (2) that workers are monitored and subjected to thorough medical supervision; and (3) that the general public includes particularly susceptible groups such as pregnant women and young children.

The size of the nuclear industry workforce (including uranium miners) in Canada is approximately 13 000 persons(10). If the maximum permissible occupational dose of ionizing radiation is received by this group, the annual rate of fatal cancers is estimated to be 4 per 10 000 persons exposed(8), or approximately 6 radiation-related fatalities per year in the Canadian nuclear workforce. In practice, the average occupational radiation dose has been much less than this limit.

In recommending maximum permissible dose limits, the ICRP recognized that it was making judgements concerning acceptable risks. Ultimately, deciding what risks are acceptable is a judgement that must be made by each national regulatory organization, and such an exercise can

---

* Surveys of nuclear installations have found actual exposure averages ranging from 0.5 to 1.0 rem per year, with a corresponding chance of fatality of 0.4 to 0.8 in 10 000 per year. Risk to workers in nuclear industries compares favourably with that in so-called safe industries.

understandably be contentious. The ICRP recommended in its 1977 report that the primary emphasis should be on keeping exposures below the maximum permissible dose limits, and in fact "As Low As is Reasonably Achievable", taking into account economic and social factors; this is known as the ALARA principle. It is commonly used in standard setting in a variety of non-nuclear industries as well.

In Canada, as throughout the world, the recommendations of the ICRP serve as criteria for radiation protection. They are the basis of regulations (under the Atomic Energy Control Act) governing the nuclear industry, of guidelines covering the radiological characteristics of drinking water, and of various provincial regulations for X-rays. The AECB, the federal agency regulating the nuclear industry, exercises, in consultation with other federal and provincial departments, the enforcement and compliance functions. Health and Welfare Canada provides advice to the AECB and conducts some of the investigation and research into radiological protection for the public. Atomic Energy of Canada Ltd. also funds research into the biological effects of ionizing radiation.

The AECB regulations incorporate the ICRP maximum permissible dose recommendations, including the application of the ALARA principle to specific situations. For example, accepting the limit of 500 millirem a year as the maximum exposure of an individual in the population leads, in practice, to deriving emission levels for specific radionuclides from nuclear industry activities to ensure that the radiation they release does not exceed the limit. These derived emission levels are specified in the AECB regulations. However, nuclear plant designers and operators are given targets of one per cent of these derived emission levels because early and continuing operating experience showed that such targets are achievable with available technology at economic costs which are not prohibitively large. Experience to date has shown that CANDU reactors have consistently met these objectives.

v) The Canadian Experience

In general, exposures from nuclear power production in Canada do not approach either the occupational or public dose limits. The estimated exposures of both the workforce and the general population due to nuclear power production in Canada are shown in Table 2. The risks to Canadians from nuclear power can be estimated from these exposures and the ICRP risk factor of 100 x 10^{-6} per man-rem(2). The total annual exposure of 1 940 man-rem to the workforce might lead to 0.2 cancer deaths eventually. The risk of lung cancer from bronchial exposure to radon daughters has been estimated by UNSCEAR(1) to be between 200 x 10^{-6} and 450 x 10^{-6} per Working Level Month (a measure of a dose to the lungs from air-borne radioactivity). Taking the upper limit of risk and assuming lung cancer is uniformly fatal, annual exposure of the uranium mining workforce of roughly 6 000 people to a collective dose between 6 000 and 12 000 WLM (1 to 2 WLM per worker per year)* leads to a statistical expectation of induced cancer deaths of 1.2 to 5.6 persons over the lifetime of the group. Adding these risks together gives 1.4 to 5.8(10) potential cancer deaths among the workforce of approximately 13 000 people. A dose of 400 man-rem a year to the public could lead to a further 0.04 cancer deaths. The sum of these risks gives a mathematical probability of about one cancer death a year from nuclear energy production at the present level. These estimates have been made for normal reactor operations and do not take account of radiation-related accidents that might occur in the nuclear industry, (exposing workers or the general public) nor do they take into account the occupational and population doses from such activities as further management of mine/mill tailings, possible reprocessing of irradiated fuel or ultimate disposal of high level radioactive waste.

The generation of electricity using nuclear energy adds radiation and non-radiation related risks of death and disease to a background of natural and man-made (non-nuclear power) radiation risk. This incremental risk is shared by the public and the nuclear industry workforce. Table 3 gives estimates of total risk of death and hereditary disease from natural and man-made radiation, including medical exposures, fallout from weapons testing and non-power, occupational exposures (source 1), and from two sources which can be attributed

---

* Recorded exposure to WLM varies with type of mine (surface or underground), season of the year, weather on a particular day (e.g. temperature inversion over a surface mine) and type of job.

Table 2

Radiation Exposure from
Nuclear Power Production in Canada, 1978 [1]
(man-rem)

	Workforce (13 000 persons)	Public
Mining and Milling		
Whole Body Exposure	70	Not detectable
Bronchial Exposure	2 960 WLM [2]	12 [3]
Fuel Refinement	7	9
Fuel Fabrication	23	Not detectable
Power Production	1 840	400 [4]
Total (man-rem)	1 940	421
(WLM) *	2 960	

Notes

1 References 1, 5, 9, 10, 11, 12

2 Working Level Month (WLM) is a measure of the dose to the lungs from air-borne radioactivity.

3 Lung dose to the population within 80 kilometres of an operating mine-mill complex (1).

4 Exposure of two million people in the area surrounding nuclear reactors.

to nuclear power generation: public and occupational exposures from 'normal' nuclear generation of electricity (source 2); and risk of death from radiation and non-radiation related occupational accidents (source 3). Sources 2 and 3 are estimated given the assumption that there is an installed generating capacity of 1 kWe per person, requiring an output of 1 000 MWe, for a population of one million people, that a complete nuclear fuel cycle with fuel reprocessing is used, and further that this condition had been in operation for many decades(8)*. The frequency of death is quoted as an annual rate per 1 000 MWe year per million population.

If nuclear generation continues to grow in Canada as planned, installed capacity per person in Ontario (where much of the present capacity and future growth occur) will approximately triple from present levels by 1995 (26). As a consequence, the numerical risk estimates in Table 3 would be expected to increase by an uncertain amount; the unknown factors in population dose-response estimates do not permit the simple extrapolation that a tripling of installed nuclear generating capacity equals a tripling of absorbed dose and consequent health risks.

---

* Installed capacity in Ontario at the end of 1979 was 5 866.4 MWe making installed capacity in Ontario somewhat less than 1 kWe per person and possibly exaggerating the present health risks from routine nuclear power generation.

Table 3
Annual Estimates of Cancers, Hereditary Diseases and Occupational Accidents(8)

Sources	Hereditary Diseases	Fatal Cancers	Accidental Deaths	Total Serious Effects
	Effects Per Year Per 10^6 People			
1. Natural and Man-made Radiation	14 - 16	18 - 22	-	30 - 40
2. Nuclear Generation of Electricity	1	1.3	-	2.3
3. Occupational Accidents (nuclear industry)	-	-	0.8	0.8
Total	15 - 17	19.3 - 23.3	0.8	33.1 - 43.1

Several comparisons could be made using the figures in Table 3. The additional public and occupational health risk due to radiation and non-radiation hazards from nuclear power is relatively small (10% or less) when compared to background risks. Provided that acceptable estimates of public and occupational risks (net of background radiation risk) in alternative energy systems and in conservation can be made, risks in nuclear power production could then be compared against these others to find which mix of generation methods yield the lowest.

vi) Risk From Abnormal Releases

The foregoing discussion has been addressed to the situation in which normal, highly probable releases of ionizing radiation have very small statistical consequences. The estimation of health risk from abnormal, accidental radiation releases in the nuclear industry presents a different picture; typically an abnormal release has a very low probability of occurring with relatively greater statistical consequences if it does happen.

Examples of abnormal occurrences in nuclear-related facilities can range from partial failure in the ventilation system in a uranium mine to equipment breakdown in a nuclear power plant. Numerical values* for the risk of major accidents are based on engineering estimates of the failure rate of individual reactor components, such as metallurgical data on the rupture of large pipes, and on the resulting probability of simultaneous or successive, combined failures of multiple and supposedly independent ("in-depth") safety mechanisms(13). Among the most serious accidents are those which could involve meltdown of the reactor core, combined with a breach of containment, and release of substantial quantities of radionuclides to the environment.

In the judgement of the AECB, the regulatory objective is to ensure that the statistical risk of harm to the public is no greater under postulated accident conditions than under normal operations of nuclear reactors. With this objective in mind, the AECB requires the designer and operator of a nuclear power plant to provide special back-up safety systems to guarantee that the prescribed cumulative dose limits to the public are not exceeded if a postulated

* Typically these estimates are not single numbers but a range of likely values. Operating experience has shown that "process failures" occur at a much higher rate than once predicted due to human error in design, installation, maintenance, or operation of nuclear reactors. A higher rate of failures can broaden the range of the original risk estimates or call their reliability into question.

accident happens.* It is the responsibility of the operator to demonstrate to the satisfaction of the AECB that this requirement is met. The regulatory approach used by the AECB involves the setting of risk limits for different kinds of reactor accidents, two of which, single and dual mode failures, are described below:

(1) A single mode failure accident refers to the complete failure of one critical reactor process system. The maximum allowable frequency of occurrence for this kind of accident is once in three years, with a maximum allowable average public radiation dose of 0.5 rem (500 millirems) per person. The expected health effects for a million exposed persons over their lifetimes is predicted to be 50 induced fatal cancers. The total public risk of induced fatal cancer would be the maximum allowable frequency of occurrence multiplied by the predicted consequence: 1/3 x 50 = 17 deaths. Depending upon the distribution of ages in an exposed population, their expected remaining lifetime is usually estimated to be between thirty and fifty years. Since the number of expected additional deaths over the lifetime of the population is 17 people, expected deaths per year would be less than one. The statistical risk to any particular person would be less than one in one million per year.

(2) A dual mode failure accident refers to the failure of a process system simultaneously with the unavailability of any one safety system. In this case, the maximum allowable frequency of occurrence of once in 3 000 years (of reactor operation) with a maximum allowable exposure of 25 rem per person would produce 2 500 expected induced cancer deaths per million exposed people, over their lifetimes. Total population risk would be, 1/3 000 x 2 500 which is less than one cancer fatality over the lifetime of the population and would be smaller as an annual figure, and smaller still if quoted as the statistical risk per person in the exposed population. Combining annual total population risk per million exposed persons for each kind of accident would yield less than one estimated cancer fatality per year.

Even if extremely pessimistic calculations of statistical risk of serious reactor accident-related health effects are used, the estimates lie well within the range of those attributed to the use of fossil fuels in electricity generation(25). A more complete discussion of the details of reactor accidents is provided in "Nuclear Accidents".

2. COMPARISON OF RISKS

As important as the technical estimation of risk to human health from a given activity is, the assessment of that particular risk will be incomplete unless comparisons are made with other sources of risk. The element of comparison in risk assessment bears directly upon the social evaluation of the acceptability of a certain technology or activity; it adds the socio-economic dimension to the question, "How safe is safe enough?". It is salutary to compare risks from ionizing radiation in the nuclear industry with three other sources: (1) natural, back-ground radiation risk; (ii) risk in alternative energy delivery systems; (iii) risk in everyday activities.

i) Back-ground Radiation Risk

One commonly made comparison involves measuring the estimated risk of a proposed activity against 'natural' background risk, i.e., that risk to which a population has traditionally been subjected. For example, the natural background contribution of ionizing radiation to which Canadians are exposed is appreciable, ranging from 100 to 200 millirem, per person, per year (much of this difference can be explained by the fact that people live at different altitudes(16)). If the lower radiation exposure estimate of 100 millirem is applied to a

---

* The limits set by the AECB allow for slightly higher doses to the general public for rare accidents than for routine releases. Several factors which provide a basis for allowing slightly higher exposures from rare releases are discussed in "Safety in the Nuclear Fuel Cycle".

total population of 20 million, the predicted collective dose of natural-source ionizing radiation would be 2 million man-rem. Based on the assumption that there is a somatic risk of 100 fatal cancers per million man-rem per year, the expected annual number of background-radiation-induced fatal cancers would be 200. Current exposure of Canadians to medical diagnostic X-rays produces a slightly lower estimate of approximately 160 cancer deaths per year (from Table 3). The estimated Canadian population exposure to ionizing radiation from normal operations of the nuclear fuel cycle is 400 man-rem per year (from Table 2), which is 0.02% of the population dose from the lower estimate of natural background radiation. This collective dose is predicted to cause less than one cancer death per year in Canada.

ii) Risk in Alternative Energy Delivery Systems

Another logical approach to the social evaluation of risk has been to compare the hazards of alternative methods of producing the same end product to find the one with the lowest risk. In the field of energy production, this comparison would address conventional fossil fuel use, unconventional, high and "low" technology fuels and conversion systems, and of course, conservation(19). A recent report by the American Medical Association(17) compared the risks of occupational and public fatalities from conventional fuel energy systems, i.e., nuclear, coal, oil, and natural gas. The findings of this report showed that, in order to fuel a 1 000 MWe electric power generating station, nuclear energy was safer than oil (2 to 3 times fewer deaths expected), and safer still than coal and natural gas, in terms of public and occupational health risks. These estimates did not include the environmental effects of the emission of fossil fuel combustion by-products. The estimates of risk to public and occupational health and safety from nuclear power generation, or any activity, are normally not single numbers but ranges of values which reflect the uncertainty in, and statistical nature of, risk estimation. It is important, in comparing alternative energy systems, to test to see if the results of the comparison are sensitive to underlying errors in the risk estimates. For example, when the most pessimistic assumptions are made about the risks in nuclear power generation (normal operations and postulated accident situations), the magnitude of overall risks remains well within the range of estimates for alternative energy systems available in the near future(1,2,3,19,25).

iii) Risk in Everyday Activities

Yet another comparison can be made to evaluate the risk from nuclear energy production; the risk of death from the nuclear fuel cycle can be

Table 4

Premature Deaths per 1 000 MWe Power Plant per 10^6 People (1,2,3,19,25)

	Coal	Oil	Natural Gas	Nuclear
Total Occupational	0.54 - 5.0	0.14 - 1.3	0.057 - 0.28	0.1 - 0.86
Total Public	1.6 - 111	1 - 100	NA (Too Low)	0.01 - 1.3
Total	2 - 116.0	1.14 - 101.3	0.057 - 0.28	0.11 - 2.16

compared with that from everyday activities or situations. Given that there is an installed nuclear generating capacity of 1 kWe per person (see Table 3), the expected fatal cancers per year are one in one million. An analysis by Pochin(6) has shown a variety of commonplace activities with equivalent statistical risk of death:

Travelling 400 miles by air

Travelling 60 miles by car

Smoking 75% of one cigarette

90 seconds of rock climbing

11 days of typical factory work (U.K.)

20 minutes of being a male aged 60 years

Calculations such as those above may beg more questions than they answer. People no doubt accept a much higher level of risk - at least a thousand-fold according to a study by Chauncey Starr(18) - for activities deemed voluntary and familiar as opposed to involuntary and new. In reality, the distinction may not be as precise as it seems. The power of advertising, peer pressure, and other social forces may significantly circumscribe 'free' choice.

3. SUMMARY

The approach to determining "how safe is safe?" for the nuclear industry is to ensure that the risks are comparable with, or less than, those of other 'safe' industries. There are, however, some difficult problems in actually implementing such an approach. The effects of low levels of radiation are stochastic and assumptions are required in estimating the risks. There has been some controversy in the field about what the appropriate assumptions should be. A generally accepted conservative approach has been adopted.

Once the risks have been estimated, the problem is one of choosing limits which the nuclear industry is expected to meet under normal and postulated accident conditions. These limits are set so that nuclear risks do not exceed those in 'safe' industries. Under normal conditions, nuclear facilities operate at levels far below these specified limits.

The difficult problem in addressing the risk issue is that society's attitude towards risks may legitimately distinguish voluntary from involuntary risk. For either category, people may also distinguish between activities of equivalent risk which differ with respect to probability and consequences. That is, society may well consider that a single large nuclear accident which occurs very infrequently is unacceptable even though it involves the same number of deaths as some other accident which occurs more frequently but with less immediately evident effects in each instance. In addressing the risks of different activities, it is difficult to build these kinds of societal preferences into the analysis. Most analyses do not take account of them and, in consequence, point to what appear to be inconsistent and anomalous situations. For example, for the average citizen in Ontario the genetic and malignant risks from nuclear power under normal operating conditions are estimated to be about equivalent to those from smoking one cigarette every two years. Public concern with the estimated risks of nuclear power and tobacco is hardly proportional to these risks. Is this a reflection of lack of knowledge of the risks or a reflection of the different weights which individuals place on voluntary and involuntary risks and on activities which have large single-event consequences rather than smaller and restricted, but more frequent impacts?

At the other extreme, it would be a mistake to avoid examining the statistical risks of different activities on the ground that, because we do not know the weights which society attaches to each, the risk estimates are not useful. This amounts to saying that however anomalous statistical risk estimates across different activities appear to be, they are the result of society's preferences and are, therefore, optimal. This is an unacceptable proposition since people are often unaware of the risks they face.

Between the two extremes of scientifically derived data on statistical risk and present spending practices is a middle ground. Risk estimates across different activities are a useful indication of where society may be overspending or underspending to reduce risk - but the analysis has to go further to take account of public preferences, seldom clearly articulated.

Application of this type of analysis in a practical way poses a number of difficult problems. It can, for example, be shown that very large amounts of money are spent to achieve small reductions in risk in some activities, among them certain parts of the nuclear industry(15). Are these expenditures simply an inconsistent and inefficient use of resources arising from the complexities of the regulatory process, or are they a more or less accurate reflection of society's preferences with respect to different types of risk? Resolution of these questions, while difficult, will have important implications for how society chooses to allocate its scarce resources to protect health, safety, and the environment.

REFERENCES AND GENERAL READINGS

(1) United Nations Scientific Committee on the Effects of Atomic Radiation. Sources and Effects of Ionizing Radiation. Report to the General Assembly. New York, 1977.

(2) International Commission on Radiological Protection. Recommendations. Oxford, Pergamon Press, 1977. (ICRP Publication 26)

(3) National Academy of Sciences. The Effects on Populations of Exposure to Low Levels of Ionizing Radiation. Report of the Advisory Committee on the Biological Effects of Ionizing Radiations. Washington, D.C., National Research Council, 1972.

(4) Burhop, E.H.S. Acceptable Risks Related to Nuclear Radiation. In: Council for Science in Society. Acceptability of Risks. Chichester, England, Barry Rose Publications Ltd., 1977. Appendix 2, pp. 63-75.

(5) International Joint Commission. Radioactivity Subcommittee. Great Lakes Water Quality, 1978. Appendix D. Windsor, Ontario, Great Lakes Water Quality Board, July 1979.

(6) Pochin, Sir Edward E. Why be Quantitative about Radiation Risk Estimates. Lecture No. 2, the Lauriston S. Taylor Lecture Series in Radiation Protection and Measurements. Washington, D.C., National Council on Radiation Protection and Measurements, 1978.

(7) Weinberg, Alvin M. "Benefit-Cost Analysis and the Linear Hypothesis." Nature 271:596, Feb. 16, 1978.

(8) Newcombe, H.B. Public Health Aspects of Radiation. Chalk River, Ont., Atomic Energy of Canada Ltd., 1978. (AECL-6330)

(9) Ashmore, J.P., and D. Grogan. Dose Statistics for Nuclear Fuel Cycle Workers in Canada. Address presented at the International Symposium on Occupational Radiation Exposure in Nuclear Fuel Cycle Facilities, IAEA/NEA Symposium, Los Angeles, June 18-22, 1979. (IAEA-SM-242/39)

(10) Canada. Health and Welfare Canada. Environmental Radiation Hazards Section. Unpublished material.

(11) James F. MacLaren Ltd. Environmental Assessment of the Proposed Elliot Lake Uranium Mines Expansion. Volume I: Denison Mines Limited, Rio Algom Limited. Toronto, 1978.

(12) James F. MacLaren Ltd. Environmental Impact Assessment of the Port Granby Project. Toronto, 1977.

(13) United States Nuclear Regulatory Commission. Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants. Washington, D.C., 1975. (WASH-1400)

(14) Cohen, B. L., and Lee. I. Sing. "A Catalog of Risks." Health Physics, 36:707, 1979.

(15) Siddall, E. Nuclear Safety in Perspective. Paper presented at the Canadian Nuclear Association Conference. Toronto, June 1979.

(16) Canada. Dept. of National Health and Welfare. Environmental Health Directorate. Environmental Radioactivity in Canada, July - December, 1978. Ottawa, to be published.

(17) AMA Council on Scientific Affairs. "Health Evaluation of Energy - Generating Sources." Journal of American Medical Assoc. 240:2193, 1979.

(18) Starr, C. "Social Benefit versus Technological Risk". Science 165:1232-1238, 1969.

(19) Inhaber, H. Risks of Energy Production. Ottawa, Atomic Energy Control Board, 1979. (AECB-1119/Revised)

(20) Lowrance, W. Of Acceptable Risk. Los Altos, Calif., William Kaufman, 1976.

(21) Rowe, W. An Anatomy of Risk. Toronto, John Wiley, 1977.

(22) Sinclair, P., P. Marstrand, and P. Newick. Innovation and Human Risk. London, Centre for the Study of Industrial Innovation, 1972.

(23) United States Environmental Protection Agency. Environmental Radiation Protection Requirements for Operations of Activities in the Uranium Fuel Cycle. Washington, D.C., 1976. (EPA-520/4-76-016)

(24) Wilson, R. "Analyzing the Daily Risks of Life." Technology Review 81:40, February 1979.

(25) Pochin, E.E. Estimated Population Exposure from Nuclear Power Production and Other Radiation Sources. Paris, Organization for Economic Cooperation and Development, Nuclear Energy Agency, Paris 1976.

(26) Royal Commission on Electric Power Planning. A Race Against Time; Interim Report on Nuclear Power in Ontario. Toronto, 1978.

SAFETY IN THE NUCLEAR FUEL CYCLE

A background paper by the

ATOMIC ENERGY CONTROL BOARD

Editors

P.E. Hamel and L. Morisset

August 1980

TABLE OF CONTENTS

TABLES:

FIGURES:

I: INTRODUCTION

This review will deal with the control by the Atomic Energy Control Board (AECB) and other agencies of radiological and chemical hazards to workers and the public throughout the nuclear fuel cycle. This includes all activities related to the production of nuclear energy, from the mining of uranium-bearing ores to the management of the radioactive wastes. It involves the following facilities:

- uranium mines and mills
- uranium refineries and fuel fabrication plants
- heavy water plants
- power reactors
- radioactive waste management facilities.

Sources of more detailed information are suggested in Appendix "A".

II: REGULATORY BACKGROUND

Legislation

The development of atomic fission for peaceful uses was recognized as early as the 1940s as an area in which international co-operation could be very fruitful. In many countries, national legislation and agencies were created to oversee the safety and security aspects of the peaceful application of nuclear technology.

In Canada, the Atomic Energy Control Act (1) was passed in 1946, creating the Atomic Energy Control Board (AECB) and giving it the power to regulate the safety and security aspects of nuclear materials and nuclear facilities. AECB Regulations require prior authorization in the form of a licence to possess, use, export, or import nuclear materials (uranium, thorium, heavy water, and radioisotopes) or to operate nuclear facilities (uranium mines and mills, refineries, fuel fabrication plants, heavy water plants, nuclear reactors, and waste management facilities) (2).

In its regulatory role, the AECB develops standards, assesses applications, issues licences, and inspects facilities. The Board also funds research programs, sometimes in co-operation with other national or international agencies such as Atomic Energy of Canada Limited (AECL) and the International Atomic Energy Agency (IAEA).

Under the nuclear Liability Act (3), the AECB also prescribes the amount of basic insurance that must be maintained by operators of nuclear installations.

Development of radiation standards

Concepts for radiological protection have been developed over the years at both national and international levels. The basis for the Canadian regulatory limits on permissible exposures originates with the recommendations of the International Commission on Radiological Protection(ICRP). Established in 1928, this organization is made up of independent eminent scientists in the field of radiological protection. Other international sources of related information include the Nuclear Energy Agency (NEA) of the Organization for Economic Cooperation and Development (OECD),the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR), the International Labour Organization (ILO), and the World Health Organization (WHO).

Radiological protection practice is directed at preventing unnecessary exposures. To this end the ICRP advocates a three-part dose limitation system which recommends that those who operate nuclear facilities;

i) assure that all practices involving exposures to radiation are justified;

ii) keep all radiation doses as low as reasonably achievable, economic and social factors being taken into account;

iii) Keep all radiation doses within specified dose limits.

Specified dose limits are set at levels low enough that acute injury will not occur and long-term effects (cancer and hereditary damage), if any, will be well within the range of low risks encountered elsewhere in society.

For normal operation, the dose limits specified in the Canadian Atomic Energy Control Regulations are 5 rem* per year for occupational exposure and 0.5 rem per year (500 millirem) for members of the public for exposure of the whole body; different limits apply for irradiation of various parts of the body. The 0.5 rem dose limit applies to the most highly exposed individual outside the plant property. Where the exposure is to radon daughters, a different unit of measurement is used known as the working level month (WLM)**. The maximum annual exposure to radon daughters is 4 WLM for occupational exposure and 0.4 WLM for members of the public.

Rather than explicitly defining what is an acceptable risk, the ICRP places primary emphasis on keeping exposures As Low As Reasonably Achievable (ALARA), economic and social factors being taken into account. The objective of ALARA is to achieve an optimum balance between the cost of reducing exposures and the health benefits resulting from the reduction. Although not specified in the AEC Act Regulations, the ALARA concept is applied by the AECB through its licensing and compliance activities. For example, experience has shown that emissions to the public from the Pickering and Bruce nuclear stations can be kept at less than 1 per cent of the annual dose limit of 0.5 rem. As a result, a 1 per cent design and operating target has been adopted by the designers/operators and the AECB for nuclear power plants built after Pickering A and Bruce A.

Non-Radiological Hazards

Some nuclear facilities must utilize large quantities of toxic and hazardous chemicals whose uncontrolled release to the environment could affect plant workers, members of the public, and the local ecology. Heavy water plants, for example, involve sulphur dioxide, propane, and hydrogen sulphide. In uranium mills and refineries, large quantities of ammonia, hydrofluoric acid, flourine, and nitric or sulphuric acids are present. Fuel fabrication plants handle beryllium and hydrogen. Power reactors also utilize hazardous substances such as chlorine, hydrogen, and various organic compounds. Where criteria for the release of these chemical substances into the environment have been developed by other government agencies, these requirements may be adopted by the AECB. Where no such requirements exist, these may be generated by the AECB.

Conventional hazards that cause industrial accidents exist in all nuclear facilities. In October 1978, the federal Department of Justice gave as its opinion that Part IV of the Canada Labour Code applied throughout the nuclear industry whenever occupational health and safety matters were not covered under the Atomic Energy Control Regulations. While the impact of this opinion is still being worked out the arrangements made so far have been based on a separation of occupational health and safety into radiological and conventional parts. The federal Department of Labour takes responsibility for the conventional side, while the AECB takes responsibility for the radiological hazards. As a result, Ontario's mining regulations and Saskatchewan's occupational health and safety regulations have been referenced into the federal legislation administered by Labour Canada. Working arrangements are being developed with uranium producers the United Steel Workers of America, appropriate provincial departments, and the AECB.

---

* A rem is a measure of the estimated effect of radiation has on the human body.

** Radon is a naturally occuring radioactive gas that decays into other radioactive elements known as radon daughters. The working level month (WLM) is a unit which combines the concentration of radon daughters in air with length of exposure.

The following sections outline specific principles and criteria applicable to each type of nuclear facility. In general, the goals underlying these specific requirements are the containment of hazardous materials and the mitigation effects in the event of releases. The ultimate objective is to minimize exposure of plant personnel, the general public, and the environment to undue hazards.

Reactors

Prevention of the release of radioactive fission products in the fuel into the work or outside environments is the basis of the safety principles for design, operation, and regulation of a reactor.

Basic safety principles and criteria for power reactors were published by the AECB for the first time in 1964. Prior to that, reactors were licensed on a case-by-case basis with the guidelines evolving from such reviews.

These guidelines require special safety systems to limit any releases of radioactivity that might result from abnormal operation of the process systems. The special safety systems must be as independent as practicable of each other and of the process systems; they must also be capable of functioning as designed 99.9% of the time during reactor operation.

In assessing the licensability of a reactor, the AECB requires the designer to assume two categories of failures: "single failures" and "dual failures".

A "single failure" or "serious process failure" is one which, in the absence of special safety system action, would result in radioactive releases potentially in excess of acceptable values. A "dual failure" is a serious process failure postulated to occur simultaneously with the failure of any one of the special safety systems, again leading to radioactive releases potentially in excess of acceptable values.

In the safety analysis, the designer must show that no serious process failure (single failure) will cause doses in excess of 0.5 rem (whole body) to a member of the public. He must also show that no combination of serious process failure and safety system failure (dual failure) will result in a dose in excess of 25 rems* to any member of the public.

The judgement of acceptability is based on the fact that dual failure accidents are not expected to occur more than once in 3 000 reactor-years. This expectation arises from the requirement to design and install high quality process systems which ensure that an assumed frequency of serious process failures of 1 in 3 years is met in practice. The special safety systems which form the defence against serious process failures must be available 99.9 per cent of the time, or in other words unavailable for no more than 1/1 000 of the time. The probability of the simultaneous occurrence of these two events is then 1/3 x 1/1 000 = 1/3 000 per reactor-year.

From the outset both the operators and regulators of Canadian nuclear reactors have recognized that operating errors and system failures may occur. The resulting approach emphasises the prevention of accidents yet provides for mitigating their consequences. This "defence-in-depth" approach means that not only must the probability of operator error and system failure be minimized but that in addition highly effective protective systems must be provided. The application of this concept includes:

i) the selection and training of competent operating personnel;

---

* The value of 25 rem has been adopted by the AECB as an acceptable standard against which to judge the analysis of a postulated accident. It is the dose level below which no permanent damage is readily observable and above which the ICRP recommends that the exposed person be examined by a physician.

ii) the design, manufacture, and construction of systems and structures in accordance with the best applicable engineering codes and practices;

iii) the physical and functional separation and independence of process systems and special safety systems;

iv) the frequent testing of special safety systems to ensure their availabilty;

v) the use of redundancy in monitoring and initiation systems (e.g. the triplication of sensing devices in the safety systems);

vi) The incorporation of multiple barriers to prevent or mitigate the effects of the release of fission products, including an exclusion zone around the reactors.

Three types of special safety systems are required. Each must be designed to meet the requirements dictated by the dose limits, and each performs a specialized function:

i) Each of the two Shutdown Systems required must be capable of terminating the nuclear fission process;

ii) The Emergency Core Cooling System must restore cooling of the reactor fuel in the event of an accident involving the loss of primary coolant due to failure of pipes, pumps, valves, etc.;

iii) The Containment System must be able to cope with the energy release associated with the loss of primary coolant and contain the radioactive fission products associated with postulated accidents.

The possibility of "extreme loading" (excessive stress) places demands on the design of these plants. Such conditions may be due to aircraft crashes, explosions, turbine disintegrations, or natural occurrences such as earthquakes, winds, and floods. The AECB requires the licensee to examine the potential for such events and where appropriate to design for protection of public, workers, and equipment.

Emergency Planning

Events more serious than those postulated above, where special engineered devices for mitigation are not provided, are taken into consideration by emergency planning. Two different sets of emergency measures must be developed prior to licensing a nuclear power reactor:

i) The On-site emergency plan relates to all people who may be on the plant site and sets out measures to be implemented by the operator should a serious accident occur. The plan is subject to the approval of the Atomic Energy Control Board, which must be notified in the event of an accident and thereafter acts in an advisory capacity;

ii) The Off-site contingency plan relates to safety measures to be implemented outside the plant boundaries. Although the existence of such a plan is a licensing requirement, the preparation, approval, and operations related to it fall under provincial jurisdiction. The off-site contingency measures vary for each facility; they may include the participation of certain federal agencies at the request of the provincial authorities.

Part of the contingency plan for Pickering as it existed in January 1978 has been appended as an illustration (Appendix B). The plan is to be implemented by the Ministry of Labour of Ontario, assisted by other provincial agencies. The Ministry of Labour is responsible for initiation action upon notification by Ontario Hydro personnel at the station.

Specific responsibilities within the plan have been accepted by Ontario Hydro and the following ministries of the Province of Ontario: Agriculture and Food, Environment, Health, Labour, and the Solicitor-General. In addition, the following federal and municipal agencies

will be informed immediately and may be requested to provide assistance: The Atomic Energy Control Board, Health and Welfare Canada, the Municipality of Metropolitan Toronto, and the Regional Municipality of Durham.

In the event of an accident, the federal Nuclear Liability Act makes the operator of a nuclear installation absolutely liable for resulting injuries and damages up to $75 million. This includes incidents at the installation or during transport of nuclear materials between installations.

The Act also provides for the establishment by the Governor-in-Council of a Nuclear Damage Claims Commission to assess compensation and pay claims in the event of an accident where claims are likely to exceed $75 million. If a Claims Commission is established the operator's liability to third parties ceases, but the operator remains liable to the Government for payment of the $75 million insurance or of the sum of all claims paid by the Commission, whichever is less.

Uranium Mines and Mills

The extraction and milling of uranium ore involves the handling of very large quantities of materials. Apart from conventional mining hazards (such as falling rock) the dangers are mostly those of high levels of dust and radioactive substances in the mine itself. In cases where the uranium concentration in the ore is high, external whole body doses due to gamma radiation may be the limiting factor. The radiation hazards are mainly due to the presence of radon gas and uranium dust in the mine air and radium in the liquid effluents from the mill. Although radon is chemically inert it disintegrates into short-lived radioactive products known as radon daughters. The process is accompanied by the release of high energy alpha particles which could cause lung cancer if inhaled.

AECB safety principles and criteria set limits for exposure of workersto radon daughters to 4 WLM* per year or 2 WLM per quarter. The AECB is presently drafting requirements governing both radiation and ventilation practices in uranium mines and mills in recognition of the intimate relationship between radon daughter concentration and ventilation. Exposure limits to silica dust which carry attached radon daughters are also being drafted. The AECB is gradually implementing a full-scale personal dosimetry program for external gamma radiation and for radon daughters exposure where feasible.

"Action levels" are a required part of the regulatory procedure which serve as signals to initiate corrective action. Action levels are determined on a case-by-case basis, after evaluation of the design of the actual ventilation system and of other factors which characterize each individual mine. These action levels are included in the licence or licensing documents.

Uranium Refineries and Fuel Fabrication Plants

The mill product (yellowcake) is purified to the reactor grade form of uranium oxide (UO_2) for the CANDU, or conversion to uranium hexafluoride (UF_6) for export to uranium enrichment plants.

These operations are carried out in the uranium refinery and UF_6 conversion plant in Port Hope, Ontario. The only existing plants in which the UO_2 is transformed into a physical and mechanical form suitable for reactor fuel are located in Port Hope, Peterborough, and Toronto in Ontario, Varennes in Quebec, and Moncton in New Brunswick. Uranium powders, liquids or vapours containing uranium, and other toxic chemicals are part of these operations. A few of these plants also handle uranium enriched in U-235 which introduces the additional problem of criticality.

---

* One working level month (WLM) is equal to 170 hours of exposure to one working level (WL). One WL is a specific concentration of radon daughters in the air.

The basic safety principles and criteria for uranium refineries and fuel fabrication plants require the following safety measures:

i) appropriate area monitoring and personal dosimetry programs;

ii) rigorous criticality control procedures;

iii) radiation safety procedures;

iv) availability of radiation protection staff;

v) adequate dust control mechanisms.

<u>Heavy Water Plants</u>

Although listed as a "prescribed substance", heavy water is not radioactive nor are the materials or wastes associated with its production. Heavy water plants are basically chemical plants. Health, safety, and environmental protection measures common to the chemical industry are applied with appropriate emphasis on public safety. All Canadian heavy water production plants employ the Girdler-Sulphide (GS) process which circulates hydrogen sulphide (H_2S) in large quantities. Both H_2S and its combustion product, sulphur dioxide (SO_2), are highly toxic at relatively low concentrations and deleteriously affect the environment. The prime safety objective of heavy water plant operation is containment of the H_2S and, where necessary and unavoidable, the control of H_2S or SO_2 releases in a manner which will not be harmful or injurious to plant personnel, the public, or the environment.

It is normal practice to operate heavy water plants so that on-site and off-site concentration targets of H_2S and SO_2 are below the odour threshold. This concentration is very much below levels which are dangerous to the health and safety of humans or injurious to the environment.

The safety principles and criteria followed by the AECB for the licensing of heavy water plants requires first that they be designed, built, and operated according to sound process engineering standards. In addition, because of the potential consequences of a major release of H_2S, the following additional precautions are taken:

i) where population density in the vicinity of the plant exceeds certain values set out in the AECB Guides, engineered protective devices must be provided to allow reduction of the required exclusion zone, e.g. the gas dispersion systems at the Glace Bay and Port Hawkesbury plants in Nova Scotia (4);

ii) design, material, and construction specifications from appropriate codes and standards must be implemented;

iii) the reliability of engineered safety and protective systems must be determined;

iv) personnel respiratory protection equipment must be provided;

v) safe work practices and operating procedures, on-site emergency procedures, and personnel training must be available;

vi) an off-site emergency contingency plan must be prepared.

<u>Waste From Nuclear Operations</u>

With the exception of heavy water plants, each type of nuclear facility generates radioactive wastes requiring some form of management.

The milling of uranium ores produces very large volumes of chemical and low-level, long-lived radioactive wastes that are normally retained on or near the surface behind retention structures such as dams. Tailings piles may occupy many acres. Radiation hazards relate to both external and internal exposures. Exposures are generally low due to the

characteristics of the tailings, the low occupational factors, and the normal practice of siting tailings areas away from populated areas. However, the potential impact on the environment of contaminated seepage discharges and the potential of retention structure failure must be considered carefully.

Refining of the yellowcake at the Port Hope plant produces relatively large volumes of chemical and low-level, long-lived radioactive wastes that are currently being stored in shallow burial facilities. Environmental impact associated with seepage discharge from such burial facilities is the principal concern.

Fuel fabrication plants generate only small volumes of low-level radioactive wastes and do not have associated management areas. Rather, the radioactive wastes are sent out for management to other facilities, such as the Chalk River Nuclear Laboratories (CRNL).

Reactor operation produces:

i) high level radioactive waste, such as spent fuel temporarily stored in water filled bays pending future final disposition;

ii) medium-level radioactive waste in the form of spent ionexchange resins and other waste, stored in engineered containers. In certain cases suitable wastes are inciner- ated and the ash stored. Worker exposure to external radiation during handling processes is the principal concern;

iii) low-level radioactive effluents or wastes which are dispersed to the environment if gaseous or liquid, if such operations are consistent with keeping releases to the environment to less that 1 per cent of licensed limits. Low-level solid wastes are bagged or wrapped and stored in solid waste management facilities.

A distinction is made between storage (a temporary method of management with the intention and the provision for retrieval) and disposal (no intent to retrieve). There is no facility licensed for the disposal of radioactive waste in Canada at this time.

The AECB insists that the creation of radioactive waste carries with it an obligation to ensure that suitable disposal methods and surveillance are available or are being developed on an acceptable time scale.

The safety principles and criteria applicable to radioactive waste management facilities include:

i) that they be designed and operated such that resulting exposures to workers and the public and releases to the environment are as low as reasonably achievable (ALARA), economic and social factors taken in to account;

ii) that storage facilities be designed and operated to ensure that the stored wastes are retrievable;

iii) that radiation fields at the boundary of radioactive waste management facilities do not differ significantly from background levels;

iv) that handling equipment and techniques used during packaging, transport, and loading operations be designed to minimize the risk of accidents.

The following apply specifically to uranium tailings retention facilities:

v) that based on comprehensive field investigations, seepage from the site will have a demonstrably low impact on the downstream environment;

vi) that the use of mill tailings is unacceptable on the down-stream side of the dam construction. Waste rock can be used provided it can be demonstrated that the impact on the general environment and on downstream waters will be acceptably small;

vii) that design and construction of embankment systems conform to currently accepted practices and safety criteria;

viii) that the use of natural lakes, with no prior provision for retrievability of settled contaminants and restoration, not be allowed;

ix) that contaminants removed from settling ponds or other engineered systems usually very high in radium-226 be safely stored pending the establishment of a suitable means of disposal;

x) that fresh water demand be kept to a minimum by suitable recycling of used waters;

xi) that suitable environmental monitoring be carried out to determine the impact of releases on ground and surface waters as required by the competent authorities;

xii) that the operator of a mill and associated tailings area be required to fulfill applicable decommissioning requirements before his obligations under an operating licence are completed;

xiii) that in case of site close-out, stablization of the tailings and retention structures be such that any drainage streams from the site will continue to meet acceptable regulatory levels of contamination and that the site will be acceptable from the standpoints of aesthetics and safety.

IV: THE REGULATORY PROCESS

Since the passing of the Atomic Energy Control Act in 1946, the AECB has been responsible for health, safety, and security in nuclear programs. A number of other agencies, both provincial and federal, are involved in either monitoring or regulation of some activities in the nuclear fuel cycle, but the AECB retains the primary regulatory and auditing function in most cases and is the only agency empowered to license the operation of nuclear facilities.

The basic approach taken by the AECB in all regulatory matters is that the applicant is primarily responsible for safety. AECB's role is to ensure that the applicants live up to their responsibility. The onus is thus on the applicant or the holder of a licence to justify the position taken on any matter questioned by the Board. The licensee must justify selection of a site, design, method of construction, and mode of operation of a facility.

The licensing process for all nuclear facilities is the most visible function of the AECB in the control of safety in the nuclear fuel cycle. The setting of performance standards and the monitoring of operations after start-up are also important components.

Reactor Licensing Process

The AECB gains assurance via the licensing process that a nuclear facility will be sited, designed, constructed, commissioned, operated, and decommissioned in compliance with established safety criteria and requirements. This is accomplished by evaluating the safety analyses submitted by the applicant and by inspection visits to manufacturers and to the site during the various phases. The key exercise is the preparation by the applicant of a Safety Analysis dealing with normal and abnormal conditions. Communication between the AECB and the applicant is established at the earliest possible stage and maintained through all phases of the project, from the initial conceptual stage through to mature operation. The information received forms the basis of the compliance program.

The licensing of nuclear facilities in Canada, as in most other countries, is a multi-step process. It involves site acceptance, construction approval, and the granting of an operating licence. Because the nature of nuclear facilities varies greatly (mines, heavy water plants, reactors, etc.) the most complex licensing process (that for a nuclear power reactor) will be used as an illustration. Fig. 1 shows the involvement of AECB and others in the approval process for a reactor.

A letter of intent at this first step constitutes formal notification of an applicant's intention to construct a nuclear facility at a particular site. This is followed by meetings between the applicant and the federal and provincial agencies concerned. The AECB does not rule on the relative suitability of various sites since site selection falls under provincial jurisdiction. The AECB will only judge whether a site is "acceptable" or "unacceptable".

Specific AECB requirements at this stage include:

i) a Site Evaluation Report emphasizing site characteristics which bear on safety;

ii) a public meeting to be held by the applicant in the vicinity of the site when the Site Evaluation Report has been made public for a reasonable length of time. This requirement could be satisfied by the applicant's participation in an environmental assessment process conducted either by a federal or a provincial agency.

The AECB's primary concern during the construction approval step is to obtain assurance from the applicant that the design will meet AECB safety criteria and principles. To this end, the following are required:

i) A conceptual reference design prepared by the applicant that translates safety criteria into design criteria for safety-related systems. At this stage, design information may be quite general and safety analyses preliminary. However, the information must be sufficient to give the Board assurance that the facility can be built to meet the safety requirements. In particular, the design must be such that in-service inspection and testing during commissioning and normal operation can be carried out;

ii) The preparation of a preliminary safety analysis where safety consequences of normal operation and certain postulated events both alone and in various combinations are analyzed in terms of the release of harmful material they could cause.

The applicant must demonstrate that the consequences of specified events do not exceed AECB criteria with respect to reference dose limits for the relevant materials. Consequently, safety analysis is the key activity in the licensing.

The processes of design and safety analysis will interact in an iterative manner; they closely parallel each other at this preliminary stage and up to the granting of an operating license. As detailed design progresses the preliminary safety analyses are refined for inclusion in the Final Safety Report;

iii) The establishment and implementation of an effective quality assurance program that covers the entire life of the facility;

iv) The submission of plans and information regarding the staffing and organization throughout the design, construction, and operation of the project. The submission must also include qualification standards for the key operator positions and the training programs proposed to achieve and maintain these standards;

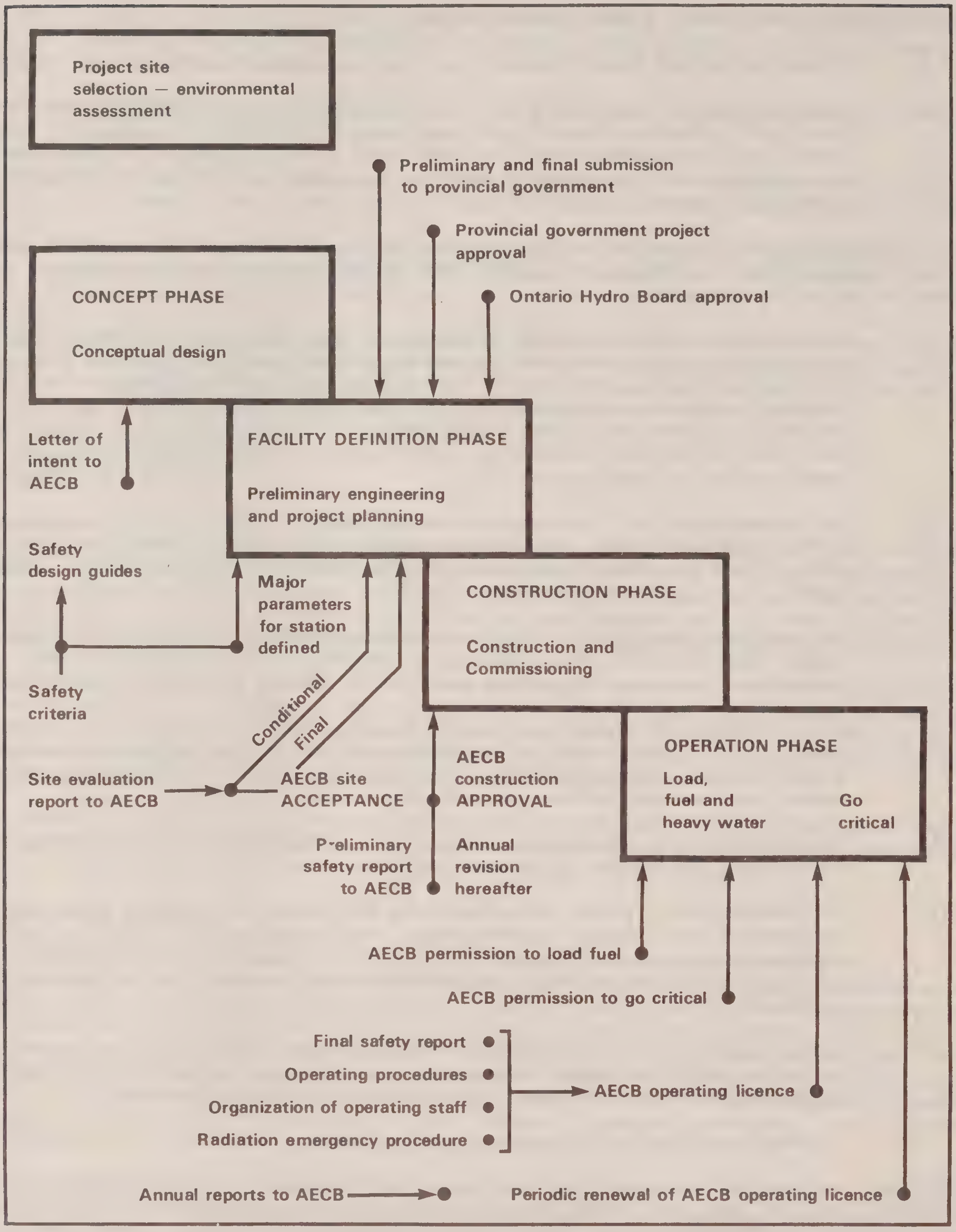
v) The preparation of a Preliminary Safety Report which is a composite document including the Site Evaluation Report, the Reference Design, and the preliminary safety analysis as they stand before construction is authorized;

vi) A formal application for Approval to Construct.

With the granting of the operating licence the AECB seeks to be assured that design and construction continue to meet AECB safety requirements; the applicant must continue to demonstrate that the facility can be commissioned and operated in a manner that will meet AECB requirements. The Preliminary Safety Report must be continously updated as new information is generated and construction progresses.

Figure 1

AECB INVOLVEMENT IN SITE AND PROJECT APPROVAL



*Adapted from: Ontario Royal Commission on Electric Power Planning, Interim Report on Nuclear Power in Ontario: A Race Against Time, p. 170.

Staffing and training programs are reviewed. Appropriate AECB examinations must be passed by the shift supervisors and control room operators; individuals filling these positions must be authorized by the AECB before fuel loading. The AECB must approve the appointment of the senior health physicist, station manager, and production manager.

The applicant must describe proposed practices with respect to waste management, emergency plans, nuclear material accountancy, and security as appropriate.

The operating licence is granted in two steps. A provisional licence is issued first which permits the applicant to start the reactor up for the first time and to operate at low power levels. With AECB approval, the reactor power is increased in specified increments up to full power. A full operating licence may be issued after the AECB staff review full power operations.

Licensing of Other Nuclear Facilities

The process described above is peculiar to nuclear reactors and is necessarily modified to account for features unique to certain other types of nuclear facilities.

The complex which includes the uranium mine, mill, and tailings retention area is licensed as a single entity; however, each component requires slightly different treatment. During the exploration phase, prior to the decision to develop a mine, there is likelihood of significant radiation hazard and/or environmental impact only if excavation is required. For this purpose, an Underground Exploration Permit is currently required before such excavation is undertaken.

Site-related considerations vary according to the type of mining technique used and are especially significant for open-pit operations. The equivalent of the construction and commissioning stages is referred to as the development stage. At some point in the development of the mine, enough ore has been removed that the mine is judged to be in operation. The AECB authorizes each step of this process.

Licensing of a uranium mill follows the general licensing process, as do refineries, fuel fabrication plants, heavy water plants, and waste management facilities.

Compliance and Enforcement

Licences are valid for a fixed period, typically 1-2 years. Licensees must maintain appropriate records of their activites and report to the AECB on a regular basis. Any irregularities in their operations must also be promptly reported to the AECB. These records and reports are inspected by designated officers in accordance with the Atomic Energy Control Regulations.

Should the operator of either a heavy water plant, a reactor, or any licensed facility fail to meet AECB requirements, the board has the legal power to curtail activities or to prosecute. In the past, such actions have been taken by amending licences to restrict operations.

Monitoring inside the boundary fence is carried out by the licensee. This includes measurements of radiation levels within the facility and of radioisotope concentrations in effluents. The results are recorded and summary reports are made to the AECB on a quarterly basis. The AECB has on-site inspectors at nuclear reactors and at the major uranium mines to carry out spot checks and provide general surveillance.

As for other nuclear facilities, inspection visits are made and samples collected for analysis in the AECB laboratories and the results reviewed by the appropriate AECB project officer.

Monitoring outside the boundary fence is generally carried out by the federal Department of the Environment or Health and Welfare Canada, or by the provincial ministries of the Environment, Health, or Labour. The results of this monitoring are available to the AECB upon

request and some information is reported routinely under ad hoc administrative arrangements. Some licensees, e.g. the electrical utilities, mount their own environmental monitoring programmes although they are not required to do so by the AECB. Results of these programs are given in quarterly reports to the AECB and summarized in the annual report prepared by the licensees.

V: ASSESSMENT OF THE SAFETY RECORD

As emphasized earlier, the primary focus of the AECB's regulatory efforts in the nuclear fuel cycle relates to health and safety. One of the AECB's basic goals is to ensure that radiation exposures from normal operation of any nuclear facility are as low as reasonably achievable and in no case greater than 5 rem/year for workers and 0.5 rem/year for any member of the public. In the case of uranium miners, the 4 WLM/year limit corresponds approximately to the 5 rem/year value. In some cases, only the data on the most exposed group, workers, are given. In all instances, it can be assumed that radiation exposures for any member of the public will be significantly less.

Power Reactors

Confidence in the safety of power reactors is derived to a extent from design evaluation, safety analyses, review of construction and operation activities and in general, the administration of a sound quality assurance program throughout the life of the installation. The record of achievement in these areas cannot be easily quantified and will not be discussed further in this paper.

Radiation Effects:

The occupational dose record for Ontario Hydro personnel in commercial reactors is summarized in Table 1 which shows the number of workers who exceeded dose limits as reported in annual reports from 1963 to mid-1979, the total period of nuclear operations for Ontario Hydro.

The highest single exposure, 7.3 rems, was in 1979 at Bruce. The next highest quarterly and yearly values were in 1971 at Douglas Point, at 5.7 and 7.0 rems, respctively. There were no detectable health effects. All temporary changes in the blood can be observed.

The sum of all doses received by a group of people is called a collective dose. Table 2 shows collective doses for nuclear reactor employees from the begining of commercial reactor programs in the two provinces where such programs exist.

The somatic effects of occupational dose may be estimated from the collective dose. The ICRP (5) uses a value of 125 fatalities per million man-rems for the risk of fatal cancer. A range of risk estimates is given by the Biological Effects of Ionizing Radiation committee (BEIR) (6), which estimated, using two different methods of calculation, that 67 to 182 excess cases of fatal cancer would occur per year per million persons exposed throughout their lifetime at a rate of 1 rad per year. One may take a rad to be equivalent to a rem for the purposes of this discussion. The BEIR estimate is then 67 to 182 fatalities per million man-rems. Using the ICRP estimate one would predict 3 excess fatal cancers due to the 23 600 man-rems received by Ontario Hydro employees. If the BEIR estimate is used, then 1.6 to 4.3 excess fatal cancers might occur.*

Anderson (7) has examined the situation in practice and found that 6 cancer deaths were observed amongst Ontario Hydro's 3 000 nuclear workers from 1970-1977. By comparison, 6.8 cancer deaths would be predicted during the same period amongst any similar group of 3 000 males drawn at random from the population of Ontario. While these statistics might appear to

---

* Note that these cancers would be in excess of those expected in the ordinary course of events for these workers. They would be distributed in time and there could be a substantial period of delay between exposure and the onset of cancer.

Table 1
Radiation Overexposures for Ontario Hydro Personnel

Year(s)	Quarterly limit (3 rems) Exceeded	Yearly limit 5 (rems) Exceeded
1963-67	0	0
1968	1	0
1969	7	0
1970	1	1
1971	6	4
1972	2	0
1973	1	2
1974	3	1
1975	7	6
1976	1	0
1977	1	0
1978	0	0
1979	2	2
Total:*	32	16

* Note that there is some overlap between the two columns, in that seven people exceeded both the quarterly and yearly limits. As a result, there were 41 rather than 48 incidents.

Table 2

Collective Dose for Reactor Personnel to end of 1978

For Ontario commercial reactors	23 600 man-rems
For Quebec commercial reactors	313 man-rems
Total	23 913 man-rems

suggest that none of the cancer deaths amongst the Ontario Hydro nuclear workers resulted from occupational radiation exposure, normal statistical variation and the fact that the latency period has not fully elapsed precludes drawing this conclusion.

For hereditary effects, assuming an average of two children for each of Ontario Hydro's 3 000 employees, the number of radiation-induced genetic defects would be 3 000 x 126*/ 1 000 000 = .08.

In other words, one of the 6 000 children might have a defect. By comparison, based on the natural incidence of 105 200 cases per million live births cited in reference (8), 105 200 x 6 000/1 000 000 = 631 of the children would be expected to suffer a gentic disorder due to natural and other causes.

Of the 236 000 man-rem receved by Ontario Hydro workers, only about 0.25 x 23 600 = 5 900 man-rem is genetically significant.

The cumulative public dose due to airborne and liquid releases from the Pickering, Douglas Point, Bruce, Gentilly, and NPD generating stations during the seven-year period from 1972 to 1978 was estimated to be 6 200 man-rem, including 3 900 man-rem due to airborne releases and 2 300 due to liquid releases. The estimated collective dose from airborne releases includes the individual doses received by the 2.2 million persons living in areas where the individual dose equalled or exceeded 1 per cent of the individual doses at the respective station boundaries. The collective dose from liquid releases includes the individual doses of the 11.4 million persons who are supplied with water from Lakes Huron and Ontario and from the Ottawa and St. Lawrence Rivers. These persons were assumed to take their entire drinking water supply, and to regularly eat fish, from these waters.

The total amount of electricity generated by these stations during the same period was 130 000 GWh, therefore collective dose per unit of electrical output was 0.05 man-rem per GWh.

The significance of the estimated collective doses from nuclear power plants (6 200 man-rem) can perhaps be better understood if compared with the collective doses from natural and medical sources. The estimated collective doses to the same populations considered above, during the same seven-year period, were 6.7 million man-rem from medical diagnostic X-ray examinations, and 16.7 million man-rem from natural background radiation; i.e., 1 080 and 2 700 times as high, respectively, as the estimated doses from nuclear power (10).

The potential health impact from these collective doses can be estimated from the ICRP risk value of about 125 fatal cancers per million man-rems. The estimated number of fatal cancers that might eventually occur amongst the populations considered above, due to the radiation doses received from 1972 to 1978, are about 1 due to nuclear power, 6 700 due to medical diagnosis, and 16 700 due to natural background radiation.

Safety targets:

In assessing the safety record of power reactors, it is useful to compare targets and actual performance. Regularly evaluated safety data include the incidence of serious process failures (SPFs) and the unavailability of safety systems. In discussing actual SPFs and safety system unavailabilities the record is compared with the assumptions made in accepting the system designs, resulting in values which can be thought of as "targets". The information used to perform such evaluation is published in the quarterly and annual safety reports prepared and released by the licensees.

---

* It has been estimated (8) that one rad (equivalent to one rem in this context) of exposure will, in the first generation, result in an incidence of 63 cases of genetic disorders per million live births. This risk estimate is based on the dose received by potential parents before they conceive children. Since the average age of conceiving children is about 30 years whereas occupational exposure cannot start before age 18, only the exposure received between age 18 and 30 is genetically significant on average. Since occupational exposure generally continues up to age 65, only about (30 - 18)/(65 - 18) = 25% of the total occupational exposure is genetically significant. (Reference (9) gives values of 20 - 23% for Canadian male nuclear workers). Thus, of the 23 600 man-rem received by Ontario Hydro workers, only about 0.25 x 23 600 = 5 900 man-rem is genetically significant. The average genetically significant dose received by 3 000 workers was therefore about 5 900/3 000 = 2 rems. According to the above risk estimate, this could result in 2 x 63 = 126 genetic defects per million children conceived by workers subject to the exposure noted above.

However the following points must be emphasized:

i) current and past practice has been to utilize safety system availability data as if the systems were either completely available to perform automatically as designed or completely unavailable. Therefore, where a malfunction only impairs the effectiveness of a safety system but does not render it inoperable, the statistics will nevertheless show the system as completely unavailable without any indication of its residual capability. An example of this happened at Pickering where an undetected small opening in the containment envelope was interpreted as a total loss of containment, whereas its effectiveness was reduced only marginally;

ii) the "targets" as defined here have changed over time;

iii) determining whether a failure that has occurred in practice is actually an SPF is not always clear-cut and is often a matter of judgement.

A serious process failure (SPF) is one which could lead to doses to the public that in the absence of the action of special safety systems (the containment, the emergency core cooling, and the shutdown systems) would exceed the reference dose limits. If any one is unavailable due to malfunction, operator error, or other causes, the safety index of the reactor is decreased.

For the purposes of safety analysis in assessing the licensability of a reactor, it was assumed that the frequency of serious process failures was once every three years in each reactor. This frequency has not been exceeded at NPD and Bruce where there have been no SPFs. The frequency has been exceeded with one SPF at Gentilly and at Douglas Point where there have been nine SPFs since 1967. At the four-reactor Pickering station there have been nine SPFs in 29 reactor-years of operation and thus, in aggregate, the frequency is consistent with the assumption. This has not been true, however, on an individual reactor basis for earlier periods of operation.

A safety system is found to be unavailable when, by testing or other methods, it is unable to automatically perform its intended function as effectively as assumed in the safety analysis. The data on unavailabilities is voluminous in quantity; no one number can characterize all of it. It is fair to say that while for many years and reactors the targets were met, there were other years and reactors where the targets were greatly exceeded. A few examples may be cited:

i) at NPD, most targets for unavailability were met from 1962 to 1978. The main exception was containment, where the target was not met for 9 of the 17 years considered, although it was met in 6 of the last 7 years. The largest ratio of actual unavailability to target in containment was 67 in 1963.

ii) at Pickering, the targets for shutdown systems were met in all but one of the 29 reactors-years under consideration. The record for containment and emergency core cooling (ECC) is worse, with the former not meeting the target for 10 reactor-years. The worst year and reactor for containment was Unit 2 in 1973 where the unavailability was 330 times target. However, the target for containment has been met in each of the last 8 reactor-years for all units. For ECC, much the same picture applies. The target was not met in about half of the reactor-years. The worst year and reactor were in 1975 at Unit 1, where the target was exceeded by a factor of 280. Of the last 8 reactor-years, the target was exceeded in 3.

iii) at Bruce, one of the two shutdown systems has always met the unavailability target. Of the 9 reactor-years to the end of 1978, Shutdown System 1 met its target each year and Shutdown System 2 exceeded it for 3 years. The worst year and reactor for shutdown systems was Unit 3 in 1977, where the target was exceeded by a factor of 22. The Bruce ECC exceeded target 6 times in the 9 reactor-years under consideration. The worst year and reactor for this system was Unit 3 in 1977, where the target was exceeded by a factor of 122. The containment target was exceeded in 2 of the 9 reactor-years under consideration.

iv) at Douglas Point, shutdown system targets were met in each year from 1969 to 1978, as were containment boundary targets. For this period, the only year the dousing target was not met was 1974, when it was between 30 and 40 times target. Emergency core injection targets were met only twice over this period, with the highest unavailability being 41 times target in 1976. Recently there have been substantial changes made to the ECC system. While some of these changes are expected to improve the availability of the system their overall effect will be primarily on its effectiveness.

There has been no serious process failure which was not followed by correct action by the appropriate safety system. The current method of determining the unavailability of a safety system is by subjecting its components to external stimuli. The results of such tests are thus a measure of the system's capability to react, and are not necessarily indicative of its potential effectiveness in response to genuine demand.

Steps have been taken to improve the performance record of process and safety systems. In addition, efforts are being extended to define failures and unavailabilities more precisely to permit discrimination between potentially alarming situations as opposed to minor irregularities.

Uranium Mines and Mills

The AECB increased its direct involvement in the regulation of uranium mines and mills in the early 1970's in response to increased awareness of occupational and environmental hazards (11). Although guidelines existed, it was not until 1967 that a regulatory limit of 12 WLM/year was explicitly introduced in Ontario; that annual limit was progressively reduced from 8 WLM in 1973 to 6 WLM in 1974 and 4 WLM in 1975. The AECB itself introduced an interim limit of 4 WLM/year in 1976 and incorporated it formally in its Regulations in 1978, thereby making it applicable at the national level. In doing so the AECB considers that the risk associated with an annual exposure of 4 WLM is no greater than the risk implied by the ICRP limit of 5 rem/year.

A study was carried out in 1976 by the Ham Commission of the statistics then available in Ontario on 15 000 miners who had worked in a uranium mine for one month or more. The total number of deaths from all causes was 956 with 81 cases being attributed to lung cancer. For the same period, and for a reference population of non-miners, the reported expected deaths from lung cancer was 45, yielding an excess of 36 deaths or 80 per cent.

The above problems gave rise to a number of recommendations by the AECB. In 1976, there were approximately 50 workers out of a total work force of about 2 000 whose exposure exceeded the 4 WLM/year limit. In 1978 there was only one overexposed worker (4.02 WLM). The reduction in occupational exposures is attributed to improvements in ventilation and better planning of production schedules. Better communication between unions, management, and regulatory agencies has also contributed. Further improvements are expected from the development of reliable personal dosimeters for radon daughters and from the introduction of standards of exposure to silica dust.

Refineries

External exposures received by the Eldorado refinery workers up to 1971 remained at a fairly constant level. In 1971, the uranium hexaflouride production facility was put into operation and due to the type of operations involved, exposures increased as indicated in Table 3.

In 1974, AECB direct involvement with the regulation of Eldorado operations was substantially increased. Efforts were made to improve equipment, operating procedures, and health protection programs to lower the external exposures received by the workers; Eldorado has now purchased a respirator testing booth and a lung counter, developed a respiratory protection program, increased the urinalysis program to better identify the problem areas and is presently replacing all inadequate equipment to eliminate the dust-producing operation.

The result has been that the total man-rem commitment at the refinery has dropped 80 per cent while the number of operating personnel has increased 100 per cent during the 1974 to 1978 period as shown in Table 3. The average individual dose has decreased by almost 85 per cent during the same period.

Table 3
Eldorado Nuclear Ltd. Employee Whole-body Radiation Exposures

	Total man-rem	Average Annual Dose (rem)
1969	38.1	.20
1970	42.1	.18
1971	168.3	.66
1972	136.9	.48
1973	212.1	.62
1974	244.0	.67
1975	210.0	.56
1976	158.5	.38
1977	68.5	.14
1978	48.1	.09

Fuel fabrication plants

As the AECB's resources increased, so did its involvement in the regulation of fuel fabrication plants. Personnel monitoring programs are now in place at all fuel fabrication plants. These include the use of personal dosimeters for measuring radiation, and whole body counting and urinalysis to determine workers' internal exposures.

Data regarding inhalation of uranium as revealed by urinalysis shows that in 1971 15 per cent of the reported results exceeded the action level. Since 1974 the incidence is less than 5 per cent. All the fuel fabrication plants use a level of 50 micrograms uranium per litre of urine as an action level (if uranium in urine reaches or exceeds that level, investigations and remedial actions are undertaken).

Heavy water plants

The primary health and safety objective at Girdler-Sulphide heavy water plants is management and control of the large inventory of toxic hydrogen sulphide (H_2S) employed in the process. While H_2S is released from the GS process system under carefully controlled conditions during normal operation and equipment maintenance activities, the gas can be released to the environment under abnormal, unplanned, or accidental conditions in a manner that may pose a threat to the health and safety of the worker and the neighboring public. The AECB's regulation of these plants is therefore aimed at ensuring that (a) the design, construction, and operation minimize the probability of an unplanned toxic gas release, and (b) in the event of such a release, the health and safety consequences are minimized.

Whereas all three Canadian heavy water plants have experienced a variety of unplanned H_2S releases as a result of process upsets, equipment failures, and/or human error, the quantities of gas released on these occasions have been relatively small in comparison with the worstcase accident considered in a typical GS plant safety analysis required by the AECB. The magnitude of off-site effects, if any, from these and from lesser controlled releases

during normal operation have been commensurately small and, in particular, no adverse public health effects have been recorded. Plant personnel exposures are primarily to H_2S, and to a lesser extent to its combustion product sulphur dioxide (SO_2) and to chlorine (C_{12}), which may be used in effuent water treatment. With the exception of one victim, who in 1976 suffered permanent brain damage from overexposure to H_2S and lack of adequate resuscitation, all personnel exposed to toxic gases have fully recovered.

Figures 2 and 3 show, on a calendar year basis for each operating GS heavy water plant, the number of occupational exposures to toxic gases and of off-site H_2S incidents. These data have been assembled from reports submitted to the AECB in accordance with requirements of the plant operating licences. Occupational exposures to H_2S are classified as acute when unconsciousness or respiratory paralysis occurs and resuscitation is required, and as sub-acute when lesser physiological effects are suffered such as nausea, disturbed respiration, eye irritation, and/or giddiness. It is generally believed that acute exposure can occur within two minutes at an H_2S-in-air concentration of 500 ppm* or immediately at concentration of 700 ppm or more. While sub-acute exposures to H_2S occur at lower doses than these, the effects of H_2S on the nervous system are first obvserved at a concentration of 100 ppm when the sense of smell is lost.

With respect to off-site H_2S incidents the data in all cases refer to distinct plant events although multiple complaints from the public and/or odour reports by plant survey crews could have been made for a given event. Most people recognized the odour at 0.02 ppm. Caution must be exercised in comparing plant data on off-site H_2S incidents. For the Bruce plant, off-site H_2S incidents have largely been attributed to incomplete H_2S combustion at the flare stack tips and measures adopted to improve combustion efficiency have had a dramatic effect in improving the situation that prevailed in 1973. For the Port Hawkesbury plant, however, off-site H_2S incidents have arisen largely as a result of process upsets and/or maintenance activities and inadequate effluent water treatment, the latter having the potential for many more off-site odours than those recorded. A system to rectify this situation is scheduled for completion by this year-end.

While recognizing that some fluctuation in frequency and severity of events is not unusual, the health and safety performance of each plant in terms of occupational exposures and off-site effects has generally improved as the plant has progressed from initial start-up towards a more mature operating phase. While these trends are encouraging and should be expected as knowledge and experience grows, the need for continued comprehensive regulatory control is warranted as the potential for massive toxic gas releases within and beyond the plant boundaries remains.

Waste management facilities

Reactors

Non-fuel wastes from reactor operations are being stored in engineered containment systems. Influx of water to these structures is severly limited by the design, and the water surrounding the reactor wastes is routinely monitored for quality. Should this water leach contaminants from the waste packages it is collected to prevent its passage into the environment.

Spent fuel lies in large tanks of water on the reactor site. The tanks are of double-walled reinforced concrete construction with an interspace between the walls. The interspace is monitored to detect and collect any leakage of water out of the bay.

Environmental releases are extremely low from all these facilities.

---

* parts per million.

Figure 2

Heavy Water Plant Statistics For Occupational Exposures to Toxic Gases

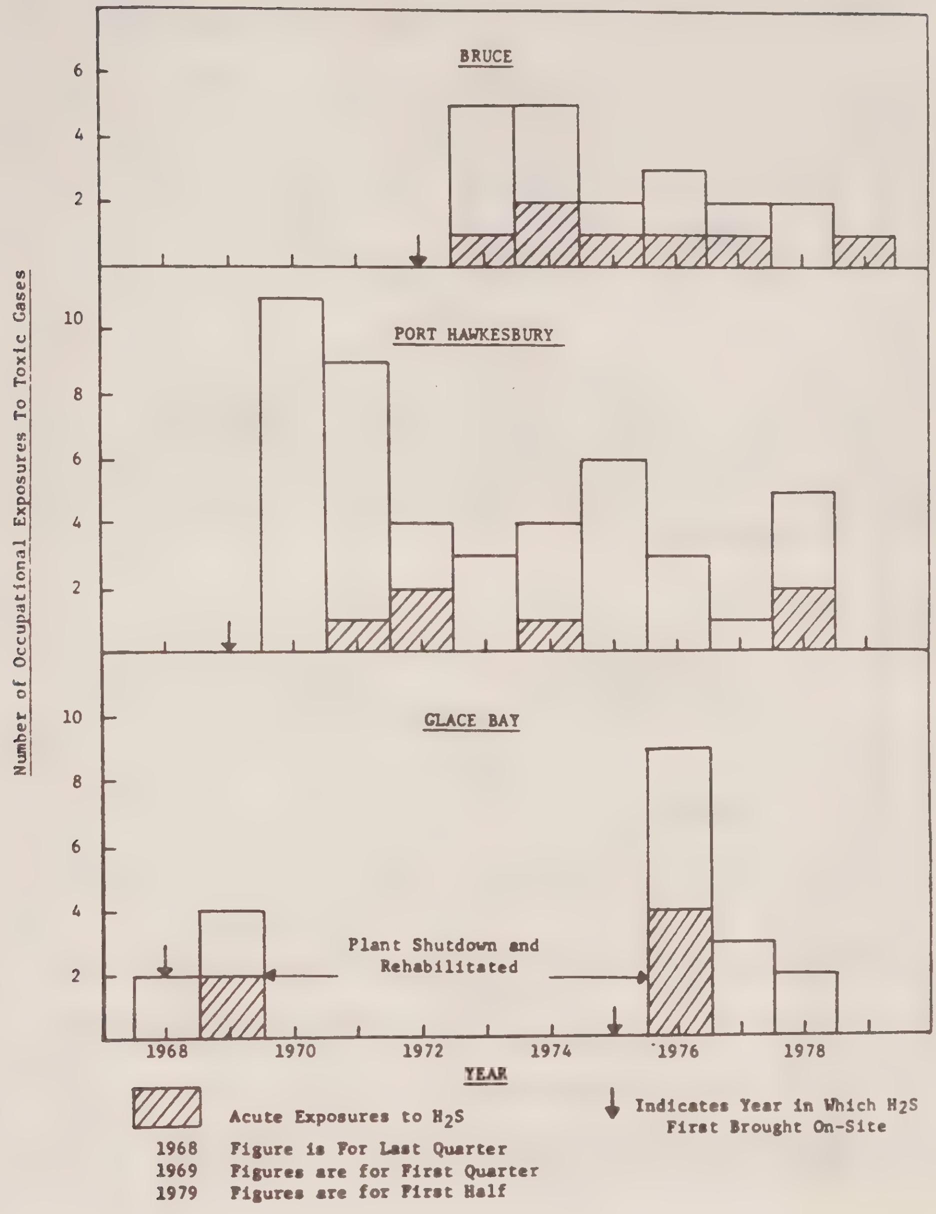
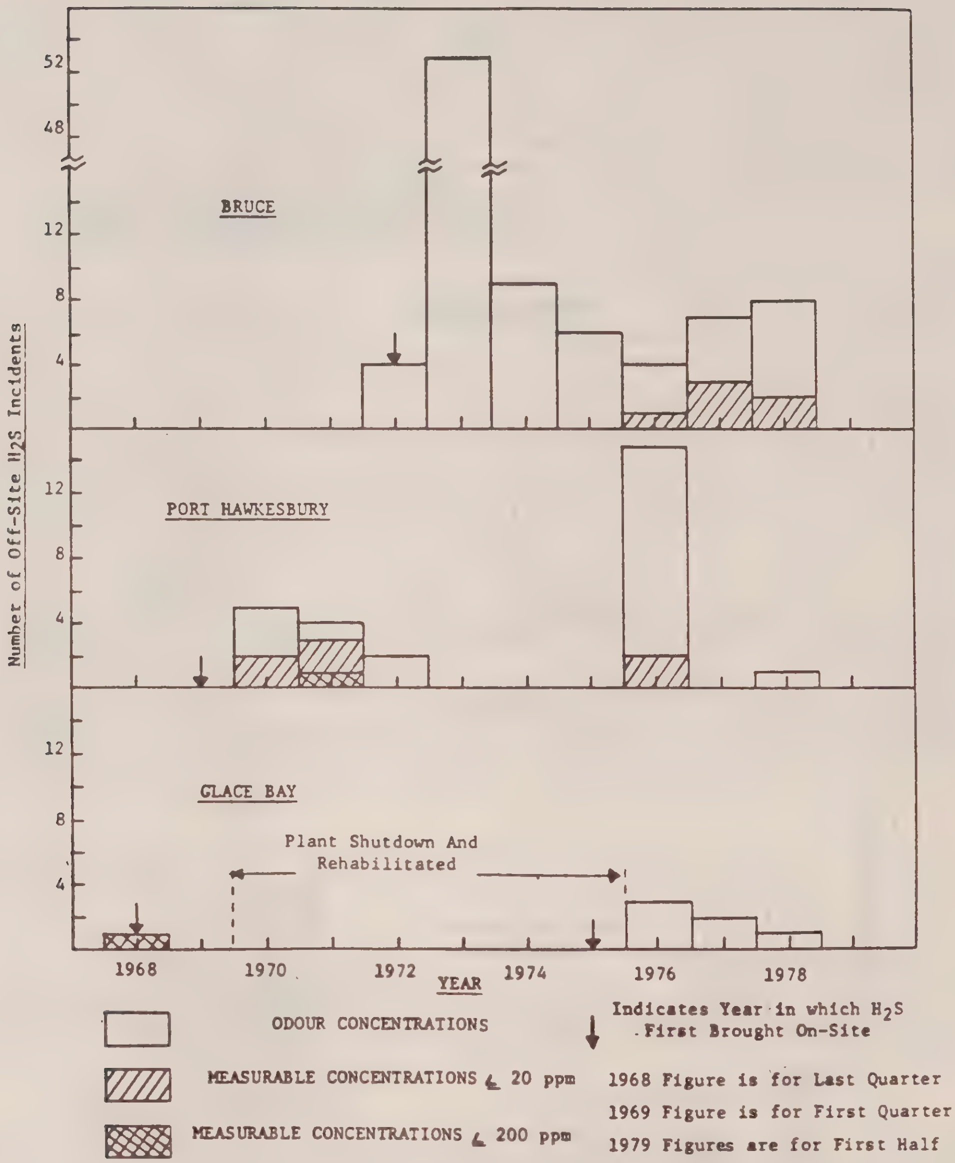


Figure 3

Heavy Water Plant Statistics For Off-Site H_2S Incidents



Refineries

Realtively large volumes of low-level, long-lived radioactive wastes are generated in the refinery operation. The radioactive contaminants are those that survived the milling process and were transferred to th refinery in the yellowcake mill product.

Radioactive wastes from the refinery in Port Hope, Ont., are being stored nearby at Port Granby in shallow, ground burial. All effluent discharges from the site are collected and treated for radium removal before being released to Lake Ontario. The discharges consistently meet the Ontario drinking water objecive for radium.

As early as 1976, concern was expressed regarding the general state of the Port Granby facility and the manner in which it was being operated. A thorough investigation of near-shore water and sediment quality of Lake Ontario adjacent to the facility was undertaken to determine any impacts associated with the low volume discharge of rather contaminated effluent. Results of the study showed that the operation of the facility was not causing any significant impact on the environment and lake. Nevertheless, the company undertook extensive remedial work to improve the operation, including the installation of a water treatment facility. The facility is operating satisfactorily and has been since 1977.

Uranium tailings

In the earlier years of operation (1950s into the 1960s) in the Elliot Lake area, routine effluent discharges, seepage and containment failures, combined with generally poor management practices, resulted in an unacceptable level of contamination of the Serpent River System. Current technology available and in use at operating facilities and at the old, dormant facilities have checked the release of contamination to the extent that water quality (and specifically radium concentration) in the Serpent River system has shown a steady improvement over the past 10-12 years.

Considering the low level of radioactivity involved, the rapid attenuation with distance of radioactive emissions from the tailing pile and more importantly, the limited time spent working in the tailings areas, occupational exposures are minimal.

Public exposures to radioactive emissions from tailings areas have been limited, largely due to low occupancy in the proximity of the piles and the rapid dissipation of emissions from the pile over short distances. The maximum gamma radiation dose rate to the public is 0.04 mrem/hr*, which was measured at one facility where public housing borders on an old tailings area (approximately 100 metres from the pile). In this development, the exposure rates within the dwellings were 0.012 to 0.015 mrem/hr. Studies in the Elliot Lake area done for the Environmental Assessment Board showed that gamma radiation from tailings areas is essentially indistinguishable from background at a distance of 1 km from the tailings. The maximum intake of radium by persons drinking water and eating fish contaminated with tailings effluents was shown to be less than the limit derived from early ICRP recommendations.**

Studies in Saskatchewan have demonstrated that the dose commitments due to both current and projected uranium mine and mill facilities are very low. Even for the critical population group located close to one mine the dose commitment is only about 20 per cent of background.

Technology now in use at active facilities is adequate to ensure protection of the environment during the operating lifetime of the facility and into any subsequent period where surveillance and intervention are available. The effluent standards for the most part are being met on a regular basis.

---

* 1 mrem/hr = 1 millirem = 1 000 rem/hr.

** The maximum acceptable limit for radium in drinking water recommended by Health and Welfare Canada is about 3 times as high as the earlier limits (27 picocuries), and so the signficance of the tailings effluents in this area is even less than previously thought.

Long-term public exposures will be reduced from present levels since some sources (e.g. mine vents) will be eliminated entirely after mining ceases, and radon and gamma radiation from the tailings will be attenuated by 10 to 100 times according to recently proposed AECB close-out criteria for uranium tailings management area. Thus it is reasonable to suggest shutdown of a mine and mill complex will be 1 to 2 orders of magnitude less than the presently low levels and would amount to less than 1 per cent background even for critical population groups.

The long-term performance of some engineered structures of tailings management systems remains to be clarified and their ability to withstand decades (or centuries) of neglect and changing climate is being considered. Optimization of tailings management and research into new methods intended to improve long-term stability and minimize health, safety, and environmental concerns to future generations are now receiving national and international attention. Results from these recent initiatives are expected to be available to the industry within the next 5 to 10 years.

REFERENCES

(1) Atomic Energy Control Act, 1946, Chap. 37, Sect. 1, as amended in Chap. 47 (1953-1954)

(2) Atomic Energy Control Regulations SOR/DORS/74-334, 4 June, 1979 and ammendments SOR/78-58, SOR/79-422.

(3) Nuclear Liability Act, 1969-1970, C. 67 Chap. 29 (1 st Supp.).

(4) "Glace Bay 'Ring of Fire'". AECL Review 10:1-3, October 1975

(5) International Commission on Radiological Protection. Recommendations. Oxford, Pergammon Pr., 1977. (ICRP Publication 26)

(6) National Academy of Sciences. Report of the Advisory Committee on the Biological Effects of Ionizing Radiation. The Effects on Populations of Exposure to Low Levels of Ionizing Radiation. Washington D.C., National Research Council, 1980.

(7) Anderson T.W. The Epidemiology of Radiation Workers. Presented to the Radiation Protection Association. Toronto, April 1978.

(8) United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR). Sources and Effects of Ionizing Radiation. New York, 1977. Annex H, Table 50, p. 539.

(9) International Commission on Radiological Protection. Problems Involved in Developing an Index of Harm. Oxford, Pergammon Pr., 1977. (Publication No. 27) Table 11.

(10) United Nations Scientific Committee on the Effects of Atomic Radiation. Ibid

(11) Royal Commission on the Health and Safety of Workers in Mines. James M. Ham, Commissioner. Report. Toronto, 1976. Table 18.

APPENDIX "A"

LIST OF SOURCE DOCUMENTS

A.1 AECB Reports

Laurence G.C. Operating Nuclear Reactors Safely. Ottawa, May 1962. (AECB-1045)

Hurst D.G., and F.C. Boyd. Reactor Licensing and Safety Requirements. Ottawa, June 1972. (AECB-1059)

MacIsaac, J.F.D. Legislation in Canada Respecting Civil Liability for Nuclear Damages. Ottawa, September 1974. (AECB-1076)

Duncan, R.M., and J.W. Beare. Siting - The Means by Which Nuclear Facilities are Integrated into a Canadian Community. Ottawa, December 1974. (AECB-1079)

Hamel, P.E., and J. H. Jennekens. Regulatory Control of Radioactivity and of the Nuclear Fuel Cycle in Canada. Ottawa, November 1976. (AECB-1100)

Gummer, W.K., et al. Background Paper for Regulations Related to the Exposure of Uranium Mine and Mill Workers. Ottawa, March 1978. (AECB-1117)

Hamel, P.E. Le contrôle des activités dans le domaine de l'énergie nucléaire au Canada. Ottawa, fevrier 1978. (CCEA-1121)

Dames & Moore. Geological Disposal of High-Level Nuclear Waste in Canada - An Assessment of the Regulator Approach. Ottawa, July 1978. (AECB-1133)

Thomas, R.A. The Atomic Energy Control Board and Nuclear Facility Quality Assurance - A Review and Update. An address presented at the Ontario Hydro Quality Engineering Conference, Toronto, Nov. 21, 1978. Ottawa, November 1978. (AECB-1147)

Paskievici, W. Proposed Safety Requirements for Licensing of CANDU Nuclear Power Plants. Ottawa, November 1978. (AECB-1149)

Advisory Panels on Tailing. The Management of Uranium Mill Tailings - An Appraisal of Current Practices. Ottawa, September 1978. (AECB-1156)

Hamel, P.E. Le rayonnement ionisant dans le milieu de travail. septembre 1979. (CCEA-1175)

Jennekens, J.H. The Nuclear Regulatory Process in Canada - 'After' Three Mile Island. Presented at a public meeting sponsored by The Association of Professional Engineers of Ontario, City of Toronto Chapters. Held at the University of Toronto, Sept. 26, 1979. (AECB-1177)

Jennekens, J.H. Nuclear Energy in Canada: in search of the definitive inquiry. An address presented to the Society of AECL Professional Employees, Oct. 4, 1979. (AECB-1178)

A.2 AECB Presentations to Inquiries

Brief to the Senate Special Committe on Science Policy. October 1968. (Also available in French)

Brief to the Royal Commission on the Health and Safety of Workers in Mines in Ontario. June 1975.

Brief to the Royal Commission on Electric Power Planning (Ontario) Volume I: Descriptive Narrative. Volume II: Schedules. October 1976.

Mémoire à la Commission Parlementaire (Québec) sur l'énergie. février 1977. (CCEA-1101)

Brief to the Cluff Lake Board of Inquiry. April 1977. (AECB-1104)

Second Brief to the Royal Commission on Electric Power Planning (Ontario). February 1978.

Submission to the Environmental Assessment Board Hearing into the Expansion of the Uranium Mines in the Elliot Lake Area. November 1978.

Presentation to the Select Committee on Ontario Hydro Affairs. July-August 1979. (AECB-1180)

A.3 Reports of Inquiries

Cluff Lake Board of Inquiry. Final Report. Chairman: Hon. Justice E.D. Bayda. Regina, 1978.

Environmental Assessment Board (Ontario). The Expansion of the Uranium Mines in the Elliot Lake Area. Final Report. Toronto, May 1979.

Environmental Assessment Panel. Report on Eldorado Uranium Hexafluoride Refinery. Ottawa, Environmental Assessment Review Office, 1979.

Environmental Assessment Panel. Report on Eldorado Uranium Refinery R.M. of Cormer Park, Sask. Ottawa, Environmental Assessment Review Office, 1980.

Environmental Assessment Panel. Report on Eldorado Uranium Policy Port Granby, Ont. Ottawa, Environmental Assessment Review Office, 1978.

Royal Commission on Electric Power Planning. Chairman: A. Porter. Report. Toronto, 1980.

Royal Commission on the Health and Safety of Workers in Mines. Commissioner: J.M. Ham. Report. Toronto, 1976.

Royal Commission on Uranium Mining in British Columbia. Chairman: Dr. D.V. Bates. Interm Report. Vancouver, 1979.

Select Committee on Ontario Hydro Affairs. The Safety of Ontario's Nuclear Reactors. Interim Report. Toronto, 1979.

A.4 Miscellaneous Documents

Aikin, A.M., J.M. Harrison, and F.K. Hare. The Management of Canada's Nuclear Wastes. Ottawa, Energy, Mines and Resources Canada, 1977. (Report EP 77-6)

Boulton, J. Management of Radioactive Fuel Wastes: The Canadian Disposal Program. Chalk River, Ontario, Atomic Energy of Canada Ltd., 1978. (AECL-6314)

Bureau of Management Consulting. An Approach for Determining the Acceptable Level of Nuclear Risk. Ottawa, 1978. (AECB-1130)

Burton, I., and A. White. The Process of Risk Assessment in National, Provincial and Local Policy Decisions on Nuclear Power. Ottawa, November 1977. (AECB-1127)

Doern, G.B. The Atomic Energy Control Board - An Evaluation of Regulatory and Administrative Processes and Procedures. Ottawa, Law Reform Commission of Canada, 1976.

Dyne, P.J. Managing Nuclear Wastes. Chalk River, Ontario, Atomic Energy of Canada Ltd., 1975.

Hamel, P.E. Quelques considérations sur les risques associés à la production de l'énergie. septembre 1977. (CCEA-1114)

Hill, P.G. Power Generation: Resources, Hazards, Technology and Costs. Cambridge, Mass. MIT Pr. 1977.

Inhaber, H. Risk of Energy Production. 2nd revision. Ottawa, November 1978. (AECB-1119).

Joint Panel on Occupational and Environmental Reasearch for Uranium Productiuon. 1979 Annual Report. Ottawa, Canada Centre for Mineral and Energy Technology, 1980.

Nagvi, S.J., D.B. Black, and C. R. Phillips. Environmental and Health Effects of Fossil Fuel and Nuclear Power Generation. Ottawa, March 1978. (AECB-1129)

Newcombe, H.B. Public Health Aspects of Radiation. Chalk River, Ontario , Atomic Energy of Canada Ltd., 1978. (AECL-6630)

Snell, V.G. Safety of CANDU Nuclear Power Stations. Mississauga, Ontario, Atomic Energy of Canada Ltd., 1978. (AECL-6329)

APPENDIX "B"

MINISTRY OF LABOUR

OFF-SITE CONTINGENCY PLAN

IN THE EVENT OF A RADIATION INCIDENT

AT THE

PICKERING NUCLEAR GENERATING STATION

Control Group

B.1 In the event of a radiation incident at the Pickering NGS as a result of which the general public may be affected, a Control Group will assemble to co-ordinate the work of all responsible agencies engaged in off-site measures of the Control Group, whose names appear in Appendix 1 to Section B, are drawn from those Government Agencies with the heaviest responsibilities and the necessary expertise in responding to a radiation incident involving the public. The members of the Control Group will assemble in an Emergency Operating Centre in the offices of the Special Studies and Service Branch, of the Ministry of Labour, 400 University Avenue, 8th floor, Toronto, as soon as possible after being alerted to the occurrence of a radiation incident at the Pickering NGS.

B.2 The Head of the Control Group* has sole decision-making authority for the Control Group. The other members of the Control Group are his advisers. Not all of them may be needed initially or all the time, particularly if the Contingency is in Category 1.

B.3 The Control Group will have available to it a compendium of information, guidelines and procedures to assist in decision making. There will be provision for, at the discretion of the Head of the Control Group:

a. Issuing of special instructions, messages or news releases on behalf of the Ministry of Labour.

b. Calling for specialized advice, by telephone or by bringing in specialists at the expense of the Ministry of Labour.

c. Authority to ask for, on behalf of the Ministry of Labour, co-operation above and beyond the extent envisaged in this Plan from any Agency of the Provincial Government.

B.4 If this Contingency Plan is set in motion, the Head of the Control Group will declare when further action under this Plan is no longer necessary. This will occur when the Head of the Control Group is satisfied that immediate concerns for public health have been allayed and that no further urgent remedial measures are necessary. He will then prepare a report for the Minister of Labour on the actions taken under the Plan.

(New edition, January 1978)

---

* In what follows, the phrase "or his alternate" is to be understood to follow every reference to the head of the Control Group.

THE NATURE OF REACTOR ACCIDENTS

Prepared by the Atomic Energy Control Board as background information on subjects related to nuclear energy. It has been reviewed by knowledgeable persons within appropriate government departments and agencies.

December, 1980

Contents

PREFACE

This is not intended to be a comprehensive review of the potential for accidents in nuclear power plants but rather gives examples only of some possible reactor accidents, their likelihood, and their possible consequences.

INTRODUCTION

As the regulatory agency for nuclear power plants, the Atomic Energy Control Board (AECB) is responsible for ensuring that nuclear power plants are sited, designed, constructed, and operated in such a fashion as to avoid an undue risk to the workers and the public. In common with those of the rest of the world, the AECB safety requirements embody the principle of defence-in-depth which, as implemented in Canada, can be described in the most basic terms as follows:

1. a nuclear power plant must be designed to minimize the frequency of serious failures;
2. notwithstanding the good design, it is assumed that serious failures will occur and therefore defences must be erected to cope with these failures;
3. further, it is a design requirement to show that should a serious failure occur, and simultaneously one of the defences should fail, the remaining defences would be capable of limiting the consequences to prescribed limits.

These general requirements are discussed in a variety of AECB publications (1, 2, 3). Very recently the AECB decided that it was necessary to clarify and expand, and in some respects modify, these general requirements (4). To implement this decision of the Board, AECB staff has prepared and issued, for public and industry comment, four licensing guides which address the requirements for:

- i) Safety Analysis (5)
- ii) Containment (6)
- iii) Shutdown Systems (7)
- iv) Emergency Core Cooling (8)

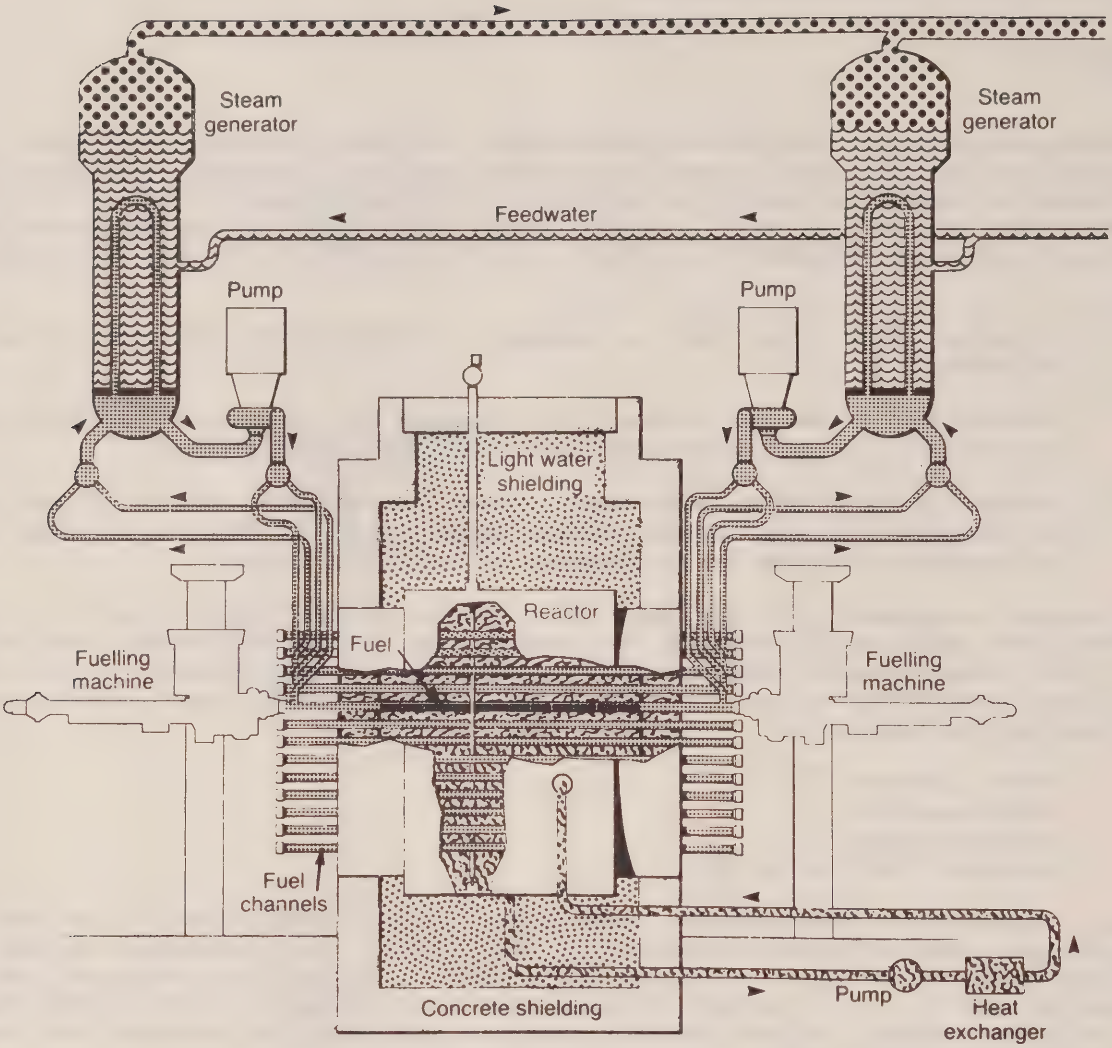
Accident experience at CANDU nuclear power plants has been good; there has not been one which has had an adverse effect on members of the public. Two independent groups have reviewed the design and operation of nuclear power plants in Ontario and concluded that they are acceptably safe (9, 10). Neither of these preceeding statements implies that reactor accidents will not happen. On the contrary, they are made with the knowledge that reactor accidents will happen in the future.

The range of accidents which are possible extends from inconsequential to catastrophic. In the following sections four particular accidents will be described which cover this range:

- i) Failure of a reactor control system;
- ii) Loss of coolant;
- iii) Loss of coolant combined with an impairment of the reactor containment building;
- iv) Reactor core meltdown.

In each case a possible course of events, the potential consequences and the likelihood of such an accident will be outlined. The discussion of consequences will address the release of radioactive materials and the resultant effects on members of the general public. It will not deal with economic consequences nor the hazard which workers would encounter in the event of an accident.

In describing these four examples, it is important to recognize that they are just that - examples. They cannot represent all possible accidents because there is such a wide variety



Source: AECL 600MW

of different initiating events each of which can have a variety of consequences, depending on the responses of the safety features and the operators. The accident which occurred at Three Mile Island was one in the spectrum of possible accidents and was perhaps more 'typical' in that it was more complex than the examples presented. The four examples do, however, cover a very wide range of probabilities and consequences.

EXAMPLE 1: FAILURE OF REACTOR CONTROL SYSTEMS

Control of the fisson process in a reactor under normal conditions is an exacting process. It is achieved by a control system which adds or removes neutron absorbers (cadmium, boron, water) to or from the reactor core. If the control system fails and too much of a neutron absorber is added, the chain reaction process will not long be self-sustaining and the reactor power will be reduced to near zero. If the failure causes too much neutron absorber to be removed there will be an increase, sometimes rapid, in the reactor power. One of the special defences, a reactor shutdown system, would need to act to stop this increase and thereby prevent potentially massive failures of reactor components. For safety analysis purposes, a failure of a reactor control system that would increase power at an uncontrolled rate is considered to be a reactor accident. Such failures of reactor control systems have occurred in CANDU nuclear power plants.

The Event

An event which occurred at the Pickering nuclear power station illustrates one way that such a failure can occur. With the reactor operating at 100% of full power, simple modifications were being made to the system which controls reactor power by adding water to or removing it from compartments in the reactor.

A fault occurred which caused the compartments to fill with water and this reduced reactor power to near zero. Reactor power was then raised to about 50 per cent of full power and the operators attempted to restore the condition of the compartments to normal. In the process, an error was made and the compartments drained rapidly. Reactor power increased rapidly from 50 per cent to 100 per cent of full power and was increasing at an accelerating rate when the independent shutdown system detected the problem and automatically reduced reactor power to effectively zero in a matter of seconds.

Consequence

In each case of a control system failure, a shutdown system intervened to terminate the power increase without any damage to the reactor fuel or other components. The consequences to members of the public were exactly zero. Therefore, while recognizing that failures of a reactor control system are serious failures, it is perhaps inappropriate to call them accidents.

Frequency

The frequency of unsafe failures of reactor control systems (those which result in an uncontrolled increase in reactor power) has been, on the average, one for each ten reactor-years of operation (8 events in about 80 reactor-years of operation, 6 of which occurred in the early years of the Pickering station). With improvements which have been made in the systems, designers estimate that a failure frequency as low as one per 100 reactor-years may be achievable.

EXAMPLE 2: LOSS-OF-COOLANT ACCIDENT (LOCA)

Most accidents in nuclear power plants (of which failure of the reactor control system is only one example) will result in zero plant damage and zero radiological impact on members of the general public if the special defences built into a nuclear power plant function

properly. However, for at least some LOCA's* the special defences (shutdown systems, emergency core cooling system (ECCS), and containment) can only limit the damage to the reactor fuel and the releases of radioactive material from the plant.

The postulated LOCA's which are considered in the safety analysis range from failure of a small (5 cm diameter) to a large (50 cm diameter) pipe. Included in this range is failure of a pressure tube inside the reactor core. In doing the safety analysis the emphasis is on searching for the particular size and location of a failure which is predicted to cause the most damage to reactor fuel (this is a critical break). It is important to recognize, however, that this is a simplification for the purposes of this discussion. In addition, but not discussed, the analysis would identify a second break critical from the point of view of required speed of response of a shutdown system, a third break critical from the point of view of required speed of response of an ECCS and a fourth critical from the point of view of required capability of the pressure suppression system in the containment building.

The Event

For a plant such as the Bruce 'A' nuclear power plant, the critical break would be equivalent to the failure of about a 25 cm diameter pipe at the coolant inlet end of the reactor. The effects of such a failure would be:

a) rapid depressurization of the reactor cooling system from the normal operating pressure of about 1300 psi** to a pressure of less than 100 psi in about three minutes;

b) as the coolant in the core flashes to steam the density of the coolant in the core falls, thereby reducing the absorption of neutrons. The heat generation rate in the fuel would increase rapidly, reaching four times the normal rate about one second after the failure, at which time the shutdown systems would halt the rise in power and reduce the power output from the fuel to about 10 per cent of normal in 10 seconds and to about 2 per cent in 10 minutes;

c) the pressure in the reactor building would rise rapidly to several pounds per square inch above normal before the action of the vacuum building and the dousing system would reduce the pressure to less than atmospheric (about 3 minutes);

d) any penetrations of containment which are normally open to the outside atmosphere (e.g., building ventilation system) would close automatically on indication of pressure rise in the reactor building to contain the radioactive materials;

e) the escaping coolant would remove much of the heat from the reactor fuel but eventually the deterioration of cooling conditions would cause fuel sheath temperatures to rise to high values (in excess of 1800 degrees F (1000 degrees C);

f) when the pressure in the heat transport system (HTS) falls to about 100 psi, there would not be much water left in the system and the EECS would act to refill the HTS;

---

* Loss-of-Coolant accident, as used here, refers to an event where coolant is escaping from the heat transport system (the system which cools the nuclear fuel with heavy water at high pressure) at a rate which is greater than the make-up capacity of the normal systems designed to keep the heat transport system full. An ECCS is then required to keep the reactor fuel cooled. Large leaks (tens of gallons per minute) can and have occurred but, being within the capacity of the normal make-up systems, they are not referred to as loss-of-coolant accidents.

** psi = pounds per square inch.

g) the combination of high fuel temperatures and low HTS pressure would result in fuel sheath failure and release of gaseous fission products into the heat transport system and then into the reactor containment building via the assumed break;

h) initially the containment building would prevent the release to the public of any significant amount of radioactive material. However, over a period of days the pressure in the containment would rise to atmospheric pressure or above;

i) to limit any pressure build-up, gases from the reactor building would be released at a controlled rate through filters by the operators;

j) from the gases exhausted, the filters would remove almost all of the particulate matter, all but a few per cent of the radioiodines, but very little of the tritium and none of the noble gases;

k) this outflow of radioactive gases which would occur over a period of days would result in radiation doses to members of the public living in the vicinity of the plant.

Consequences

The major concerns in considering a LOCA are the radiation doses which would be received by an individual living near the plant boundary and the total radiation dose to all the people in the vicinity of the plant. The predicted consequences are subject to uncertainties in many areas. Three of the major areas of uncertainty are:

i) the quantity of radioactive gases and vapours which escape from the fuel and into the reactor containment building;
ii) the quantity of radioactive gases which escape containment;
iii) the weather conditions which prevail at the time of the accident.

The uncertainties in the quantity of radioactive gases and vapours which escape from the fuel include the uncertainties about the effectiveness of any ECCS. Will the ECCS be successful in rewetting and cooling the fuel in the reactor as predicted on the basis of extrapolations from laboratory tests? Is it possible that the rewetting of some fuel channels will delay for an extended period of time the rewetting of others due to "short-circuiting" of the emergency coolant? Will fuel bundle and fuel channel distortions under accident conditions interfere with cooling by the ECCS to the point that additional gaseous fission products will be released from the uranium oxide fuel? There are no simple answers to these and other questions and therefore an analysis of the consequences of a LOCA involves a process of conservative assumptions in some cases and best engineering judgement based on extrapolations from available experimental information in others.

The uncertainties in the quantity of radioactive materials which escape containment are associated with the deposition of fission products in containment, the efficiency of filters, the correctness of operator actions associated with venting of the containment, and the leak tightness of the containment.

Weather conditions can also be a significant variable. For a given release of radioactive material from the plant, the predicted radiation dose to an individual at the plant exclusion boundary could easily vary by a factor of ten or more depending on the assumptions that are made with respect to the prevailing weather conditions and therefore the dilution of radioactive materials in the atmosphere.

There is a fourth factor which would affect the radiation dose to people; protective actions such as evacuation of the affected populace or distribution of tablets of a stable iodine compound. Use of such tablets can greatly reduce the radiation dose resulting from inhalation of radioactive elements of iodine. The assumption is made that there would not be any evacuation of people or distribution of tablets despite the fact that the release of radioactive materials are assumed to continue for many days.

Bearing in mind the uncertainties, one can then examine the predicted radiation dose to an individual who lives at and remains at the plant exclusion boundary as well as to the general populace. For the Bruce 'A' plant the designers have estimated that the dose to an individual at the plant exclusion boundary could range from:

Thyroid dose	- 0.01 to 60 rem*
Whole body dose	- 0.02 to 0.3 rem

Although estimates of dose to thyroids as high as 60 rem have be made in extreme cases, a more realistic estimate would be less than 3 rem.

Using a higher value in each case and assuming that:

a) there is a uniform population density of 250 persons/km^2 (640 persons/sq. mi.)**;

b) that unfavourable weather conditions will persist indefinetely,

the total dose to the population within 64 kilometers (40 miles) of the plant would be predicted to be no more than:

Thyroid dose	- 3.7×10^5 man-rem
Whole body dose	- 1 300 man-rem

Based on widely accepted relationships between radiation dose and health effects, the consequences of such doses to an individual are predicted to be 0.6 per cent chance (1 chance in 170) of developing thyroid cancer in their lifetime due to the 60 rem dose to the thyroid. The chance of a fatal cancer of the thyroid would be about 0.03 per cent (1 chance in 3 300). There would be a 0.004 per cent chance (1 chance in 25 000) of fatal cancers due to the whole body dose of 0.3 rem.

The consequences of a population dose of 3.7×10^5 rem to thyroids are predicted to be two additional fatal thyroid cancers in the affected population. If the population dose was calculated on the basis of the more realistic estimate of a 3 rem dose to the thyroid of the most exposed individual the population dose would be 19 000 man-rem and a 10 per cent chance of one additional fatal cancer would be predicted. The consequences of the 1 300 man-rem whole body dose to the populace are predicted to be a 16 per cent chance (1 chance in 6) of one additional fatal cancer and 10 per cent (1 chance in 10) of producing one additional genetic defect in all succeeding generations.

Frequency

Because there have been no loss-of-coolant accidents in CANDU nuclear power plants, it is not possible to predict the frequency of such occurrences based on operating experience. Instead, it is necessary to base predictions of frequency on information from other types of plants. A survey of high pressure piping systems in non-nuclear plants suggests a frequency of less than one large pipe failure for each 1 000 reactor-years of operation (11). (The critical break discussed above would be a large pipe failure). The frequency of small pipe failures would be expected to be higher (perhaps one every 10 to 100 reactor-years) because there are many more small pipes.

One should not attribute a high degree of accuracy to these estimates of frequencies. Clearly, with 80 reactor-years of operation of CANDU nuclear power plants and no small pipe failures in a reactor cooling system (of sufficient size to be called a LOCA), an estimate of

---

* Radioactive elements of iodine usually would be included in the releases under accident conditions. If inhaled, these radioiodines would be concentrated in the thyroid gland and would result in a significant dose to the thyroid without any significant dose to the rest of the body. The uncertainties discussed above could increase the range of these predicted values.

** This density is approximately that of the town of Markham which has a population of 60 000 in an area of 210 square kilometers.

one in every 10 reactor-years seems too high. One every 100 reactor-years appears more likely and such an estimate would not be inconsistent with experience elsewhere in the world. The estimate of less than one large pipe failure per 1 000 reactor-years of operation cannot be proved on the basis of reactor experience in Canada and the rest of the world. One can only say that the estimate is not inconsistent with reactor experience.

If the estimate of less than one large failure per 1 000 reactor-years is correct, it would mean that with 10 operating CANDU reactors the average interval between large LOCA would be at least 100 years. With 25 operating CANDU reactors, the average interval would be at least 40 years.

EXAMPLE 3: LOCA COMBINED WITH IMPAIRMENT OF THE REACTOR BUILDING

The LOCA sequence described earlier is a very simplified sequence. Since neither machines nor human beings are perfect it is reasonable to expect that unforseen problems will occur. In Canada it is an AECB requirement to assume that if a LOCA (or variety of other accidents) occurs there will also be a failure in either a shutdown system, the ECCS, or the reactor containment system.

For illustrative purposes, a LOCA combined with a failure in the containment system will be described. While recognizing that a number of different failures in the containment system could be postulated (e.g., failure of dousing, failure of building pressure relief valves to open, or deflated seals on airlock doors*), the specific failure in the reactor building ventilation system (failure of ventilation dampers** to close) is described.

The Event

The sequence of events would proceed as before until step (g). The remainder of the sequence would be:

h) assuming that the exhaust dampers on the building ventilation system fail to close, the containment would be open to the outside atmosphere through a ventilation duct having a diameter of about 8 inches (in the case of a Bruce 'A' reactor);

i) for approximately the first 3 hours after a LOCA, the containment system would be at sub-atmospheric pressure due to the action of the vacuum building;

j) during this 3 hour period, air would flow into the containment through the ventilation duct in which the dampers had failed to close;

k) after this 3 hour period there would be a continous outflow of air from the containment carrying with it radioactive material;

l) the situation would be restored to "normal" when and if the dampers could be closed.

Consequences

Bearing in mind the uncertainties discussed earlier (p. 6), maximum doses to an individual standing at the plant exclusion boundary for an indefinite period after a large LOCA would be:

Thyroid dose	- 155 rem
Whole body dose	- 2 rem

---

* To prevent the escape of radioactive material from a reactor building all doors are sealed by inflated rubber seals.

** Under normal operating conditions there is a controlled flow of air into the reactor containment building to ensure a suitable environment for workers. This air is exhausted from the building and discharged through a ventilation stack. Should an accident occur, the ventilation lines into and out of the buildings are isolated by the automatic closure of dampers in the lines.

Again assuming a uniform population density of 250 persons/square kilometer (640/sq. mi.), the dose to the population within 64 kilometers of a plant would be:

Thyroid dose	- $5.9. \times 10^5$ man-rem
Whole body dose	- 7 100 man-rem

Again, based on widely accepted relationships between radiation dose and health effects, the consequences of such doses to an individual are predicted to be a 0.08 per cent chance of developing a fatal cancer of the thyroid in their lifetime due to the 155 rem dose to the thyroid and a 0.025 per cent chance of fatal cancers due to the whole body dose of 2 rem. The consequences of a population dose of $5.9. \times 10^5$ rem to thyroids are predicted to be three additional fatal thyroid cancers in the affected population. The consequences of the whole body doses of 7 100 man-rem to the populace are predicted to be one additional cancer death and a 50 per cent chance of one additional genetic defect in all succeeding generations.

Frequency

On page 7 estimates of the frequencies of LOCA were presented:

Small LOCA	- once per 100 reactor-years
Large LOCA	- less than once per 1 000 reactor-years (i.e., less than 10^{-3}/year).

Tests of the dampers which isolate the ventilation duct (along with tests of all the instrumentation and logic associated with this isolation feature) show that isolation is unavailable about 0.3×10^{-3} year/year; that is, about 2.6 hours per year. Therefore the probability of a large LOCA occurring with isolation unavailable would be the product of these two numbers: $10^{-3} \times 0.3 \times 10^{-3} = 0.3 \times 10^{-6}$ per reactor-year. With 25 operating reactors the probability would be about one in 130 000 per year.

Even this simple example requires some qualification. The probability of one in 130 000 per year is based on the expectation that a large LOCA will have no effect on the availability of the isolation system. While the isolation system is designed to be unaffected by a large LOCA, one cannot rule out some unforeseen mechanism which could render the isolation system ineffective.

The above discussion has been limited to a LOCA combined with one particular mode of containment impairment. There are other possible failure modes for containment. The example discussed is clearly only one member of the family of postulated accidents called "LOCA with Impaired Containment".

EXAMPLE 4: CORE MELTDOWN ACCIDENTS

Core meltdown accidents of the type to be described here have never occurred in any commercial power reactor, although the sequence of events at Three Mile Island went partway along the path. Nor has any study on core meltdown accidents been done for the CANDU reactor (although initial examination of possible sequences is being sponsored as part of the AECB's research program). In the absence of relevant Canadian information, the work done by N.C. Rasmussen, as described in the Reactor Safety Study (WASH-1400) issued in 1975 by the U.S. Nuclear Regulatory Commission (12) is used. The following information borrows extensively from that document and, although not strictly applicable to CANDU reactors, does give useful illustrative information on very serious potential accidents. The differences in the design of CANDU and U.S.A. light water reactors can significantly alter the sequence of events, and can reduce or increase the probability and the consequences of an accident.

The Event

The Reactor Safety Study defined two broad types of situation that might potentially lead to melting of the reactor core: a LOCA, and transients.

In the event of a LOCA, the normal cooling water would be lost from the main cooling system but core melting would normally be prevented by the action of the ECCS. However, if the ECCS failed to act, melting of metallic components of the core and eventually of the uranium oxide fuel itself would probably occur.

The term "transient" refers to those situations where there is an uncontrolled increase in reactor power or a loss of normal cooling flow, both of which require the reactor to be shut down. Following shutdown, the decay heat removal systems act to keep the core from overheating. However, if the reactor fails to shut down or the decay heat removal systems fail, melting of the core would ensue.

The Rasmussen study conservatively assumed that if any melting occurred, then complete core melting would occur. It was then predicted that the molten core, consisting of a mixture of molten uranium oxide, stainless steel, zirconium, and other core structural materials, could melt through the bottom of the 20 cm thick steel reactor vessel and through the 3.69 metre thick concrete base slab of the containment structure. The study estimated the time for going through the reactor vessel to be 1 to 1 1/2 hours and through the base slab to be an additional 13 to 28 hours. The molten mass was then predicted to sink into the ground an additional 3 - 15 metres before coming to rest. (This sequence is often portrayed as the so-called "China Syndrome".) However, much of the core's radioactive material, which strictly speaking has escaped from containment, is prevented from reaching the environment because the ground acts as an effective filter. Further, considerable radioactive decay would have occurred by the time groundwater leaching could contribute to the spread of contamination. Thus, while this was considered the most likely sequence following a major core meltdown, it would not necessarily produce a dispersal of the bulk of the core's radioactive material into the environment.

Much larger consequences could be associated with core meltdowns which also cause failures in the containment structure above ground. If the containment sprays malfunction or are damaged by flying debris (generated by a LOCA or transient) the steam being released from the reactor core would not be condensed. This steam, along with various vapours and noncondensible gases could cause failure of the containment structure due to overpressurization. Hot zircaloy from the fuel sheaths and steel would also react with water to produce large volumes of hydrogen. Detonation of this hydrogen (reacting with oxygen) might damage the containment or, if not, the heat of combustion combined with high steam pressure would at least add to the pressure loads on the structure. A further contributor to containment pressurization would be the large quantities of carbon dioxide generated as the molten core melts through the concrete base slabs. Another possibility is one in which the molten fuel falls into the pool of water in the bottom of the reactor vessel; this could result in a steam explosion which could rupture the reactor vessel with the formation of flying debris which could, in turn, damage the containment structure. All post-meltdown occurrences which threaten to damage or breach the containment structure can result in the release of substantial amounts of radioactive material to the environment.

Consequences and Frequency

The Reactor Safety Study calculated the health effects and the probability of occurrence for many possible combinations of radioactive material release magnitude, weather conditions, and population exposure. The results are shown in Table 1.

In addition to these health effects, a nuclear accident may contaminate the surrounding area and require relocation of the populace. For the most likely core melt accident, having a probability of occurrence of one in 20 000 per year, little or no contamination would be expected. Consequences associated with other probabilities have been estimated in the Study and are as follows:

Table 1

Approximate Value of Early Effects and Latent Effects

Chance per year[e] per reactor	Early Illness	Early Fatalities	Latent[b] Cancer Fatalities (per year)	Genetic[c] Effects (per year)
	Consequences			
1 in 20 000[a]	1.0	1 [d]	1.0	1.0
1 in 1 000 000	300	5 [d]	170	25
1 in 10 000 000	3 000	100	460	60
1 in 100 000 000	14 000	1 000	860	110
1 in 1 000 000 000	45 000	3 300	1 500	170
Normal incidence per year[f]	4×10^5		17 000	8 000

(a) This is the predicted chance per year of core melt.

(b) This period would occur approximately in the 10 to 40 year period after a potential accident.

(c) This rate would apply to the first generation born after the accident. Subsequent generations would experience effects at decreasing rates.

(d) Not given in study. Values have been interpolated from the other values in the table.

(e) Chance per year that a combination of events will occur which have the consequence given.

(f) Normal incidence in the 10 million people who might be exposed in a very large accident over the time period that the potential reactor effects might occur.

Table 2

Land Area Affected By Potential Nuclear Power Plant Accidents

Chance per year	Consequences: Decontamination Area (Sq Mile)	Consequences: Relocation Area (Sq Mile) (b)
1 in 20 000	0.1	0.1
1 in 1 000 000	2 000	130
1 in 10 000 000	3 200	
250		
1 in 100 000 000	(a)	290
1 in 1 000 000 000	(a)	(a)

(a) No change from previously listed value.

(b) Area from which people would need to be removed until decontamination was complete.

In connection with the estimates of probability one should keep in mind the comments of The Risk Assessment Review Group under the chairmanship of H.W. Lewis, as recorded in its report published in September, 1978 (13, p. vi-vii):

> "...We are unable to define whether the overall probability of a core melt given in WASH-1400 is high or low, but we are certain that the error bands are understated. We cannot say by how much. Reasons for this include an inadequate data base, a poor statistical treatment, an inconsistent propagation of uncertainties through the calculations, etc...
>
> We do find that the methodology, which was an important advance over earlier methodologies applied to reactor risks, is sound, and should be developed and used more widely under circumstances in which there is an adequate data base or sufficient technical expertise to insert credible, subjective probabilities into the calculations."

CONCLUSION

The foregoing illustrative description of the nature of reactor accidents has necessarily been simplified. The four accidents described were chosen from a large set of potential failures and failure combinations. While they are typical of that set and while they cover the potential range of probability and consequence, there are many other possible accident sequences which are not really characterized by these four.

The values given for the probabilities of specific accidents and their associated consequences are open, no doubt, to argument. This paper identifies the many uncertainties associated with these estimates and these uncertainties should be kept in mind when interpreting these values.

In general, the quoted consequences bound or over-estimate the likely consequences by using conservative assumptions where uncertainties are felt to exist. Thus, the likely effct of this approach would be to produce consequence estimates which are too large.

Finally, only reactor accidents have been discussed. For a discussion of the elements of reactor safety, see "Safety in the Nuclear Fuel Cycle".

REFERENCES

(1) Hurst, D.G., and F.C. Boyd. Reactor Licensing and Safety Requirements. Ottawa, 1972. (AECB -1059)

(2) Atchinson, R.J. Nuclear Reactor Philosophy and Criteria. Ottawa, 1979. (AECB - 1180)

(3) Hamel, P.E., and L. Morrisset. Safety in the Nuclear Fuel Cycle. Ottawa, Atomic Energy Control Board, 1980. (INFO - 0015)

(4) Domaratzki, Z. Reactor Safety Requirements in Times of Change. Ottawa, Atomic Energy Control Board, 1980. (INFO - 0005)

(5) Atomic Energy Control Board. Licensing Guide No.39: Requirements for the Safety Analysis of CANDU Nuclear Power Plants. Draft. Ottawa, 1980.

(6) ----. Licensing Guide No. 40: Requirements for Containment Systems for CANDU Power Plants. Draft. Ottawa, 1980.

(7) ---. Licensing Guide No. 41: Requirements for Shutdown Systems for CANDU Nuclear Power Plants. Draft. Ottawa, 1980.

(8) ---. Licensing Guide No 42: Requirements for Emergency Core Cooling Systems for CANDU Nuclear Power Plants. Draft. Ottawa, 1980.

(9) Royal Commission on Electric Power Planning. Chairman: A. Porter. Report. Toronto, 1980.

(10) Select Committee on Ontario Hydro Affairs. The Safety of Ontario's Nuclear Reactors. Interim Report. Toronto, December 1979.

(11) Giggons, W.S., & B.P.Hackney. Survey of piping failures for the Reactor Primary Coolant Pipe Rupture Study. San Jose, California, General Electric Co., 1964 (GEAP 4574) .

(12) U.S. Nuclear Regulatory Commission. Reactor Safety Study: an Assesment of Accident Risks in U.S. Commerical Nuclear Power Plants. Washington, D.C., 1975. (WASH - 1400)

(13) Risk Assessment Review Group. Report to the U.S. Nuclear Regulatory Group. Chairman: H.W. Lewis. Washington, D.C. 1978. (NUREG/CR - 0400).

APPENDIX 1

KNOWN REACTOR ACCIDENTS HAVING SIGNIFICANT CONSEQUENCES

ACCIDENT "TITLE	DATE AND LOCATION	SUGGESTED READING (see numbered reference below)
NRX	1952; Chalk River, Ontario	1, 2, 3, 4
WINDSCALE	1957; Windscale, England	5, 6,
NRU	1958; Chalk River, Ontario	7, 8, 9,
SL -1	1961; Nuclear Reactor Test Station, Idaho, U.S.A.	10, 11, 12, 13,
FERMI	1966; Chicago, U.S.A.	14, 15,
LUCENS	1969; Lucens, Switzerland	16, 17,
BROWN'S FERRY	1975; Decatur, Alabama, U.S.A.	18, 19
TMI	1979; Harrisburg, Pennsylvania	20, 21, 22

APPENDIX 1: REFERENCES

1. Thompson, T.J., and J.G. Beckerley, eds. The Technology of Nuclear Reactor Safety. Vol.1. Cambridge, Mass., MIT Press, 1964. pp. 619 - 622.

2. Lewis, W.B. An Accident to the NRX Reactor on December 12, 1952 Chalk River, Ontario Atomic Energy of Canada Ltd.,1953 (AECL - 232)

3. Hurst, D.G. The Accident to the NRX Reactor,Part II. Chalk River, Ontario, Atomic Energy of Canada Ltd., 1953. (AECL - 233)

4. Henderson, W.J., A.C. Johnson and P.R. Tunnicliffe. An Investigation of Some of the Circumstances Pertinent to the Accidents to the NRX Reactor of December 12, 1952. Chalk River, Ont., Atomic Energy of Canada Ltd., 1953. (Report NEI-26)

5. Thompson, pp. 633 - 636.

6. Accident at Windscale No. 1 Pile on 10 October, 1957. Report presented to the British Parliament. London, 1957. (Report Cmnd. 302)

7. Thompson, pp. 688 - 689.

8. Greenwood, J.W. Contamination of the NRU Reactor in May 1958. Chalk River, Ontario, Atomic Energy of Canada Ltd., 1959. (AECL - 850)

9. Rupp, A.F. "NRU Reactor Incident." Nuclear Safety 1:70 March, 1960.

10. Thompson, pp. 654 - 682.

11 Tardiff, A.N. Some Aspects of the WTR and Sl-1 Accidents. Washington, D.C., United States Atomic Energy Commission, 1962. (Report ISO - 19308)

12. General Electric Co. Final Report of the SL-1 Recovery Operation. Washington, D.C., United States Atomic Energy Commission, 1962. (Report ISO - 19311)

13. Buchanan, J.R. "SL - 1 Final Report." Nuclear Safety 4: 83-86, March 1963.

14 Scott, R.L. "Fuel-Melting Incident at the Fermi Reactor on October 5, 1966." Nuclear Safety 12: 123-134, March-April 1971.

15 Atomic Power Development Assoc. Report on the Fuel Melting Incident in the Enrico Fermi Atomic Power Plant on October 5, 1966. Washington D.C, United States Atomic Energy Commission, 1968. (Report APDA - 233)

16. Miller, J.M. "Incident at the Lucens Reactor". Nuclear Safety 16: 76-79, January-February 1975.

17. Commission d'enquete technique sur l'incident de Lucens. Rapport final sur l'incident survenu a la centrale nucleaire experimentale de Lucens Le 21 janvier 1969. Paris, 1979. (French translation of original report in German).

18. Scott, R.L. "Brown's Ferry Nuclear Power Plant Fire on March 22, 1975." Nuclear Safety 17: 592-611, September-October 1975.

19. Rippon, S. "Brown's Ferry Fire." Nuclear Engineering International 20: 461-462, May 1975.

20. President's Commission on the Accident at Three Mile Island. Chairman: J.G. Kemeny. The Need for Change: the Legacy of TMI. Report. Washington, D.C., 1979.

21. United States. Nuclear Regulatory Commission. Investigation into the March 28, 1979 Three Mile Island Accident. Washington D.C., Office of Inspection and Enforcement, 1979. (NUREG - 0600)

22. Panell, B.J., and F.R. Campbell. Three Mile Island - A Review of the Accident and its Implications for CANDU safety. Ottawa, Atomic Energy Control Board, 1980. (INFO - 0003).

RADIOACTIVE WASTE MANAGEMENT AND DISPOSAL

Department of Energy, Mines and Resources
November, 1980

TABLE OF CONTENTS

1. INTRODUCTION

Many of the production processes which characterize a modern industrial economy result in the creation of waste products which are highly toxic even in low concentrations; which are not (or are only slowly) degraded by natural processes; and which may, if releases are uncontrolled, present a threat to human health and the natural environment over very long periods of time (or forever in the case of substances which do not degrade). Well known among such substances are lead, organic mercury, and PCB's. Radioactive waste produced by the nuclear fuel cycle is only one of many types of waste product which require careful management, storage and, ultimately, disposal.

The nuclear fuel cycle produces radioactive wastes in different forms, solid, liquid, or gaseous; in different volumes, ranging from large amounts of relatively low-activity mine and mill wastes to small amounts of highly radioactive spent fuel; and with different radiological characteristics, from relatively short-lived fission products to very long-lived nuclides such as plutonium. While each type of waste presents specific management and disposal problems, each is radioactive and must be carefully managed so that it does not pose an unacceptable hazard to human health or the natural environment.

In the short term, radioactive wastes are carefully stored, supervised and monitored to ensure that any releases fall within acceptable regulatory limits. In the longer term, concern over the disposal of very long-lived radioactive elements is focused on the development and demonstration of safe techniques for permanent waste disposal. To this end, Canada and other countries with nuclear programs are actively engaged in research and development to determine acceptable methods of long-term disposal.

2. THE CATEGORIES OF RADIOACTIVE WASTE

Radioactive waste can be defined as:

> a by-product or scrap material containing or contaminated with radionuclides in concentrations greater than that which is considered acceptable for uncontrolled use or release. (5)

Nuclear wastes are produced at every stage of the nuclear fuel cycle (see figure 1). They occur in a variety of physical and chemical forms and are characterized by different radionuclides in different concentrations. Because of these differences, there are a variety of ways to classify nuclear wastes:

(a) On the basis of origin of the waste (e.g. reactor operation, mining and milling);

(b) On the basis of physical and chemical form of the radioactive waste, such as gaseous, liquid, or solid, each of which may require different management techniques;

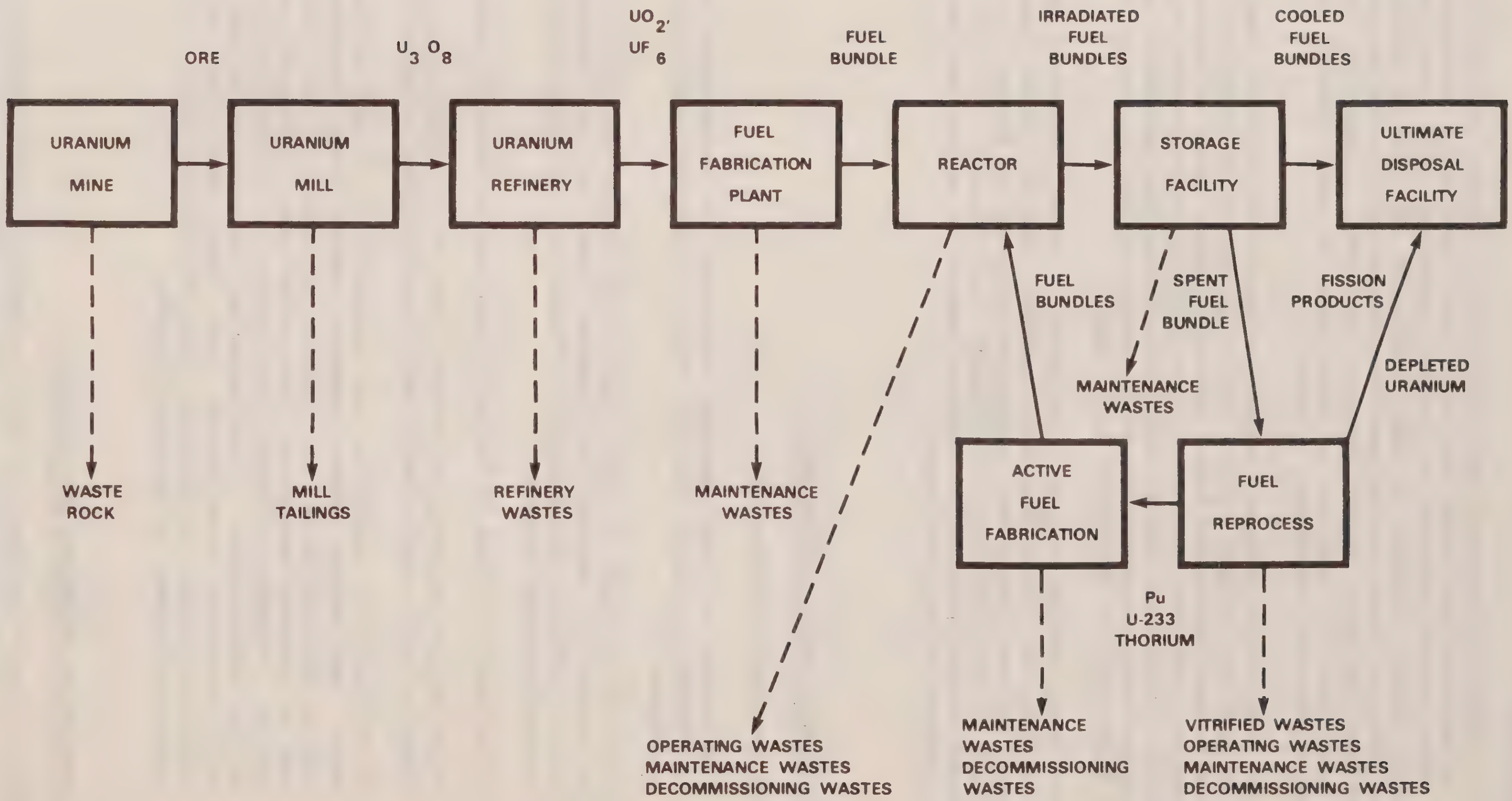
(c) On the basis of composition and concentration of radionuclides contained in the waste. Such vaguely defined operating terms as "high", "medium", or "low" level are used to characterize wastes. Examples of medium and low level wastes are filters used in cleaning exhaust air from nuclear power plants and contaminated protective clothing. Examples of medium level wastes are contaminated primary circuit filters and ion exchange media. Some medium and low level wastes may only require storage for a relatively short period, until their short-lived radioactivity decays to negligible levels. In contrast, spent fuel wastes contain radionuclides which will require containment for hundreds of years.

3. WASTE MANAGEMENT OBJECTIVES AND PRACTICES

A statement of the objectives for waste management should establish general critera for assessing waste management proposals as well as specifying what role consideration of future

Figure 1

THE NUCLEAR FUEL CYCLE:
PRODUCTS AND WASTE



generations will play in developing such programs. While there is no clear statement of the overall national objectives for radioactive waste management for the nuclear fuel cycle as a whole, the objectives of Atomic Energy of Canada Ltd.'s (AECL) management program with respect to spent fuel and reactor wastes have been established as:

> Safety:
>
> to manage radioactive materials so that hazards are negligible,
>
> Responsibility:
>
> to manage radioactive materials in such a way that the trouble and concern to future generations in maintaining safety will be minimized or eliminated.
>
> Boulton (ref. 4, p.1-2)

Two fundamentally different courses of action are available to achieve waste management objectives. As defined in ref.8, p.19 they are:

(a) containment of radionuclides in order to achieve the required degree of isolation from man's environment by suitable storage or disposal methods;

(b) dispersion and dilution of radionuclides into the environment through the release of effluents.

Dispersion, of course is an acceptable alternative only when the resulting radiation exposure falls within levels established by health and environmental protection principles.

Given this general background, waste storage and waste disposal can be defined. The disposal of radioactive wastes will be accomplished when the wastes are sufficiently:

(i) isolated by natural or engineered passive containment; or

(ii) reduced in concentration by decay or dispersal,

such that the residual risks to mankind are so much lower than everyday risks that they are fully acceptable.

The storage of radioactive material is accomplished when the material is placed in a situation where it can be maintained under active supervision (monitored, cooled, isolated, etc.) so that no radioactivity above the regulatory limits is released.

Storage implies continued surveillance and retrievability, while disposal implies that no monitoring is ultimately required. If the objective of minimizing impacts on future generations is to be attained, it is clear that for long-lived radioactive waste no permanent reliance should be placed on human surveillance, control, or monitoring. A system for the permanent disposal of radioactive wastes is therefore one which relies on passive means - generally natural and/or engineered containment - to reduce the risk to man and the environment to a very low level. All other systems should be classified as storage systems.

4. WASTE MANAGEMENT AND THE NUCLEAR FUEL CYCLE

(i) Mine and Mill Wastes

As most uranium ores contain only a small fraction of valuable uranium (from 0.5 to 1.5 kilograms per tonne), the mining and milling of uranium generates very large amounts of waste. With the bulk of Canadian commercial ore, approximately one tonne of tailings is produced per kilogram of product. Along with each tonne of solids, about two tonnes of liquid waste are discharged. These mine and mill wastes pose an immediate environmental problem due

to potential radiological and non-radiological pollution, as well as a long-term disposal problem associated both with radioactive elements and heavy metals. Additional pollutants arise from the use of chemicals in the milling process.

Naturally occurring radioactive elements contained in the tailings include uranium 238, thorium 230, radium 226, radon 220, lead 210, and thorium 232. Mining and milling make them more available to the biosphere where they pose a potential hazard to the environment from airborne dust, from emanation of radioactive radon gas, or from potential leaching of radionuclides. The release of these radionuclides to the biosphere presents risks to man if they are ingested or inhaled.

If these radionuclides are taken in with food or drink, they may be either absorbed through the intestinal wall to the blood stream, or discharged directly. If they are absorbed, the body chemistry disposes of them in various ways. Radium, polonium, and thorium are known bone seekers and concentrate in the bone-forming tissues. Because they are only slowly replaced, they continue to irradiate and damage local tissues. With a sufficient accumulated exposure, bone cancer is the primary result, with leukemia a lower probability.

Radon (which is an inert gas) would normally be exhaled after being taken into the lungs, but any decay products (e.g., radon daughters which are solid atoms) breathed in, or formed while the radon is in the lung, may be deposited on the lung tissues. Such material is removed relatively slowly and in this situation, a sufficient level of exposure can lead to lung cancer.

It is important to note that none of these materials lodges preferentially in the reproductive organs, so that any damage to human genes from this natural radiation would be only a minute fraction of the somatic damage.

Mine and mill wastes also contain a number of non-radioactive substances with potentially serious environmental impacts. These include ammonia and nitrates from blasting operations, sulphide minerals which can lead to acid runoff, heavy metals, and process chemicals such as the sulfuric acid used in the milling operation.

Wastes are discharged in slurry form to tailings ponds in which the solids in suspension are allowed to settle. The liquid effluent is treated by the addition of chemicals to be compatible with the water system to which the effluent will eventually be discharged. Barium chloride is added to precipitate dissolved radium in the settling ponds. Specific treatment of the effluent is not required for other radionuclides and heavy metals which are generally held within the settled tailings. Effluent from tailings generated in operating mines is monitored frequently for radioactive content.

The present surveillance methods are designed to ensure that negligible quantities of radioactivity are released to the biosphere in the water effluent and seepage. Removal of solid wastes which have in the past been used as construction material is now prohibited. Airborne release of dust particles can be minimized by soil coverance vegetation. Such preventive measures are required by the licensing procedures of the Atomic Energy Control Board (AECB). Enforcement of the terms of the Board's license is achieved with the co-operation of provincial authorities and the mining company.

In general, current management techniques, so long as they are properly applied, provide adequate protection for human health and the environment. The concern, however, is for waste management and disposal over the very long time periods during which mine tailings will remain a potential radiological hazard. In the immediate term, the amount of radioactivity contained in tailings piles is small relative to the amount contained in highly radioactive spent fuel. The main concern with tailings as such is not magnitude but duration. The radioactive nuclides contained in tailings have very long lifetimes relative to most of the radioactive isotopes in spent fuel, so that in the longer run (after 1 000 years or so) the radiological hazard presented by mine tailings is comparable to that of spent fuel.

Tailings are currently in storage, and the issue of permanent disposal has yet to be resolved. At present there are no universally accepted criteria for determining whether a long-term disposal problem exists. Thus, it is necessary to reach agreement on the criteria which permanent disposal must meet; decide whether, in light of these criteria, a problem

exists; and if a problem does exist, determine how to resolve it. In the meantime, several alternatives to existing practices have been suggested and are being evaluated, including:

(a) Further improvements to surface deposition, e.g. cover with sealant or several metres of clean fill, solidify chemically, etc;

(b) Deep burial by returning tailings to the mined-out region, although for underground mines only a little more than 50 per cent of the tailings could be disposed of in this way;

(c) Deep lake disposal by deposition in undisturbed deep water;

(d) Removal of noxious components either by modifications to the present milling process, by adopting completely new milling processes or, for existing tailings, by reprocessing.

Because different orebodies differ significantly in conformation and geography, it is likely that the disposal method for each mine will differ. In other words a single generic solution may not be adaptable to all tailings sites without modification, so that research work may be necessary on all potential disposal options and sites.

Because of the large volume of mill tailings, sites close to the mill will be preferred. Hence site selection is unlikely to be the critical step which it is in spent fuel disposal. In this particular case, acceptance of the proposed disposal method by the regulatory authorities may be sufficient for final approval.

Many questions regarding tailings management are unresolved: With whom will ultimate responsibility for long-term waste management lie? Who will bear responsibility for administering tailings long after a mine has ceased producing and companies ceased to exist? Who will bear responsibility for already abandoned sites which pose a potential hazard?

(ii) Uranium Refining

Eldorado Nuclear Ltd. has been refining uranium at Port Hope, Ontario since 1942, although the refining of radium from the pitchblende ore from Great Bear Lake was begun there in 1935. In 1953, radium production ceased at the refinery and since then it has continued as the only refinery in Canada for uranium. The plant refines uranium concentrates (mainly U_3O_8) received from the mill into ceramic grade uranium dioxide powder (UO_2) for CANDU reactor fuel and uranium hexafluoride (UF_6) for export to enrichment plants and eventual use in light water reactors.

Wastes arising from these processes consist of a solid material containing the impurities removed from the concentrate; a slightly contaminated ammonium nitrate solution from UO_2 production, and contaminated ash from UF_6 production. Variations on the present processes and the dismantling of old equipment have also resulted in a variety of different wastes.

Since its inception the refinery has generated many different waste products and their disposition has a very involved history. Many of the wastes from the radium and the early uranium refining operations were recovered and reworked by Eldorado, Vitro Corp. in the U.S., and Deloro Mining and Smelting. Various sites were used both for storage and for burial of different waste products. Some sites, such as Monkey Mountain and Pigeon Hill, were on Port Hope town property, other sites in Welcome and Port Granby were purchased by the company. As a result of apparently unco-ordinated and improperly controlled waste management practices, a large percentage of private residences in Port Hope had radioactively contaminated materials incorporated into their structures or on their grounds, leading to the measurement of higher than normal levels of radon gas and radiation.

Following the recognition in 1975 that such material should be better controlled, the Task Force on Radioactivity was formed by the governments concerned and has since proceeded to remove the contaminated material and ship it to a waste management site located at Chalk River, Ont. This cleanup operation is now almost complete.

Port Granby is the only waste storage site which is still operational in the Port Hope area, and along with the old dump sites is now subject to extensive supervision and control under AECB regulation. A succesful experimental program was carried out in co-operation with Northern Ontario mining companies investigating the possibility of recycling this material through the ore milling process. The current solid refinery wastes contain higher uranium concentrations than some ore and are now procesed with the ores through the mills. The radioactive constituents in this case are thus amalgamated with the rest of the tailings.

Eldorado is storing their ammonium nitrates, but these could be used for fertilizer. They are also trying to introduce a revised process by which this material would be fully recycled in their plant.

In general, waste disposal problems associated with refining are being resolved. The quantities of radioactive wastes for disposal directly from the refining operations in future will be much reduced.

(iii) Fuel Fabrication

The fuel fabrication process consists of UO_2 powder preparation, pressing, sintering, and grinding. The resulting pellets are loaded into zirconium alloy tubes which are then sealed and assembled into bundles before packing and shipping.

Radioactive waste arises mostly from the UO_2 pellet operation, but also from items which are rejected at one of the many inspection points. Most of the grinding waste and the pellet scrap is returned to Eldorado for recycling through their uranium refinery. The wastes from housekeeping have a very low level of contamination but are shipped to the Chalk River Nuclear Lab site. Waste management from such plants does not present any difficulty.

(iv) Irradiated Fuel

During reactor operation, energy is obtained from the fission (splitting) of the U_{235} atoms in the natural uranium fuel as well as plutonium fissioned in situ. Two new families of materials are also produced by the fission process. First, the splitting of the uranium atoms produces new atoms which are called fission products. The fission products have half lives which vary from less than a second to years, eventually decaying to non-radioactive elements while emitting beta and gamma radiation in the process.

Most of the fission products of concern have half-lives of about 30 years and therefore their concentration is reduced by 100 000 times in 500 years, to levels where the hazards arising will be small or neglible. Fission products have no commercial value and are therefore properly described as radioactive waste.

Also produced during the operation of the reactor are radioactive nuclides of heavy elements such as plutonium, americium and curium. These are created when U_{238} atoms absorb neutrons produced during the fission process. They are collectively called actinides because their atoms are heavier than the atoms of the element actinium. The majority of the actinides decay by means of alpha particle emissions and some have half lives in the thousands of years. This means that the radioactivity from these materials will decay to negligible levels only after periods of tens or hundreds of thousands of years. The radiation hazard from a vault containing these long-lived wastes becomes equivalent to that from a natural uranium ore body after several hundred years.

Of most interest among the actinides is plutonium 239. Plutonium 239 is, like uranium 235, a fissile nuclide, and thus a potentially valuable source of energy. Because spent fuel contains plutonium it may at some time in the future be recycled for its energy content. Since uranium is currently available at relatively low cost, recycling (which would involve costly and sophisticated technology) is not currently economically attractive in Canada, nor is it likely to become so in the next 20 to 30 years given current projections of uranium price and availability. In the meantime spent fuel can be safely stored until it is either reprocessed or the decision is made to dispose of it as a waste product. Permanent disposal facilities will not be available for several years. In the meantime the irradiated fuel will be accumulated in storage.

Methods of spent fuel storage are well developed. Currently spent fuel bundles are stored in water filled bays at each reactor site. The water in the bays removes the heat generated by radioactive decay of the fuel, and the storage method provides enough shielding to ensure that radiation levels outside the storage area are kept below acceptable levels, and provides assurance that if the fuel cladding should fail, any release of radioactivity would be contained (1). Operating experience with storage systems indicates that this technology can be safely relied upon until a decision is made about reprocessing and technologies for permanent disposal are demonstrated.

Methods of permanent disposal of spent fuel or of reprocessing wastes are currently under development by AECL. It is worth mentioning that after a certain long but finite period of time - several hundred years - the radioactivity contained in spent fuel or reprocessing wastes will decay to levels equivalent to natural uranium ores which are part of the environment.* Thus an important consideration in the development of waste disposal programs is the demonstration that wastes can be effectively isolated from the environment for this length of time.

The program is based on the concept of isolating wastes by interposing a number of man-made and natural barriers between the waste and the biosphere. The identified barriers are:

(i) the waste form - a very low solubility material such as ceramic or glass;

(ii) the container - of welded corrosion resistant metal;

(iii) the back fill - of bentonite, clay or similar material to absorb incident ground water and prevent it reaching the waste and to absorb and seal in any released radiocativity;

(iv) the geological environment - 500 to 1 000 metres separation is provided from the biosphere;

(v) the quality of the rock - provides very limited flow passages lined with absorptive substances resulting in low radionuclide velocity;

(vi) the biospheric dilution - even if a radionuclide penetrates the previous barriers, it may never become accessible to man.

The first three barriers are engineered or man made and research on them is mostly pursued in the laboratory. It is already clear that a wide range of delay periods (up to thousands of years) may be achieved by the selection of different engineered barriers. The first containers and various alternative waste forms for irradiated fuels have been made. These and other samples are undergoing extensive testing.

The latter three barriers are natural and are much more difficult to research.

The Canadian waste disposal program centres on disposal in hard rock formations known as plutons, which are "underground mountains of rock that formed as a single unit from molten magma inside the earth's crust" (Boulton, ref.3, p.48). Plutons are attractive for a number of reasons:

- they occur in one of the oldest and most stable geological formations - the Precambrian Shield;
- they are highly impermeable - water flow is very low in the absence of fractures and fissures;
- the technology of deep hard rock mining is readily available;

---

* Based on the concentration of radioactivity per cubic metre of the facility volume.

- plutons have no known mineral value;

- they are widely available in the Canadian Shield.

Four field sites are already being explored in this program for research purposes - White Lake, Chalk River, Whiteshell (Manitoba), and Atikokan. These are all granitic bodies and cover the range of fracture densities. Drilling has taken place at all four sites to depths of 200 metres and at Whiteshell and Atikokan 1 000 metres has been reached. In addition to the checking of samples for rock composition, homogeneity, mechanical and physical properties, many geophysical surveys and hydrogeological tests have been performed. These tests are giving information regarding the structural integrity of the rock body, temperature distribution and its effects, the expected size of homogeneous rock, the chemistry of the groundwater encountered, and its flow.

All of the information gathered in this work is being combined in a series of mathematical models which quantifies the movement of radionuclides through this series of barriers and determines the resulting health and environmental impact over time. This pathway analysis will help in establishing the acceptability of this concept of waste disposal, and also plav an important role in site selection and licensing stages.

Additional studies examine the potential consequences of a number of natural or man-made events. These include:

- naturally occuring events such as an earthquake or glaciation;

- changes caused by thermal stresses or radiation effects;

- human intervention.

The conclusions of the pathways analyses conducted to date in Canada and elsewhere have been summarized by Boulton: (ref.3, p.53.)

> While it is impossible to predict accurately the future over the time scale of the lifetimes of the long-lived radionuclides, it is possible to estimate the consequences of a loss of integrity of the geologic containment. Several analyses have been made of the consequences on the assumption that water and a pathway are available to transport the radioactive nuclides to the biosphere and man. These analyses have varied in their sophistication, but all either conclude or lead to the conclusion that the dose to man at any time will be considerably less than he is subjected to every day from naturally-occurring background radiation.

In addition to the pathways analysis, an examination of environmental effects (including social and economic effects) and a safety analysis (including the results of catastrophic natural events) are being prepared. The results of all this work will be published as a series of concept assessment reports. The first of this series will be published in 1981 and it is intended that a version of adequate scientific merit to start the process for approval of concept assessment will be published in 1983. The final version, with all of the proven detail necessary, should be completed in 1988. An independent Technical Advisory Group will continuously monitor and review progress.

Public input is essential throughout the entire process from concept assessment to site selection. Ongoing consultation with local governments and with the public in general is an important part of the development program. Plans for site selection and the construction of a disposal facility will be subject to public environmental impact assessment processes.

(v) Other Reactor Wastes

An operating CANDU power station produces radioactive wastes other than irradiated fuel. Among these are the filters and ion exchange columns which remove radioactive corrosion products and fission product contamination from the heavy water coolant; maintenance wastes such as valve packings, seals, and replaced items from the radioactive circuits; rags, towels,

and contaminated clothing used by the maintenance workers, some radioactive gases which escape from the coolant (e.g. tritium, carbon 14, argon 41) and contaminated water from laundries, floor scrubbing, etc.

At the moment, low and medium level solid wastes are stored at the reactor site, or at shallow burial sites. A number of disposal options are being considered. For the more hazardous wastes, disposal in a pluton at the same site as the fuel waste vault is the reference concept. However, simpler and less costly methods may satisfy the waste disposal criteria for the bulk of this classification.

Methods are under development for the reduction of volume and the immobilization of these wastes. For volume reduction, incineration and pressure compaction are in use and for immobilization, incorporation within pitch or concrete are under test. Such processing is aimed at producing an adequately stable solid insoluble form.

It is proposed that alternative geological media be investigated to determine their suitability for disposal of low-hazard long lived wastes. The uranium refinery wastes may also benefit from this work. The potential options in addition to the reference concept for disposal of long-lived low-hazard wastes are:

(a) shallow ground burial in relatively dry unsaturated zone of overburden;

(b) disposal at intermediate depth in the saturated zone of clay or till formations;

(c) disposal in disused mines.

5. CONCLUSIONS

At present, the radioactive wastes in Canada are in storage. Hazard to man and the environment is prevented by careful supervision and monitoring. The issue of concern is the permanent disposal of such waste.

Concern over problems raised by radioactive waste management has led to a number of sometimes extensive reviews of the progress and problems raised by waste management. The majority have been optimistic about the prospects of success. The conclusions of the Hare report (1), issued by EMR in 1977, are representative:

> "There are good prospects for the safe, permanent disposal of reactor wastes and irradiated fuel, and we see no reason why the disposal problem need delay the country's nuclear power program, provided that the government proceeds immediately to the program of research and development in the following recommendations." Hare Report (1), p.6.

However, despite repeated assurances that nuclear waste disposal presents no insoluble scientific, engineering, or environmental problems, the issue remains in the mind of the public and some members of the scientific community as a serious unresolved issue associated with the development of nuclear energy. In several countries (Sweden, Germany, and the United States) public concern over long term waste disposal has become a major factor cited in opposition to nuclear energy. In Canada, the Royal Commission on Electric Power Planning in recommendation 5.17 of their Final Report, states that:

> If progress in high-level nuclear waste disposal R & D in both the technical sense and the social sense, is not satisfatory by at least 1990, as judged by the technical and social advisory committees, the provincial and federal regulatory agencies, and the people of Ontario - especially in those communities that would be directly affected by a nuclear waste disposal facility - a moratorium should be declared on additional nuclear power stations.

Three general issues can be highlighted. First, there is a concern that society is imposing a serious burden on future generations by leaving behind a legacy of radioactive wastes which may prove difficult to manage. Presumably, clear proof that passive waste disposal systems will perform adequately is required to resolve this concern. This naturally raises a second question. How can it be proven that waste disposal systems will perform adequately over very long periods of time? This is an area in which reliance must be placed on the results of scientific experimentation and modelling - concepts which non-scientists may often find both difficult to grasp and unconvincing. Finally, there is the problem of establishing what the words "perform acceptably" mean. A clear general statement of overall principles applying to radioactive waste management has yet to be agreed upon within Canada or internationally.

In addition there are a number of more specifc waste management issues which will have to be addressed. Who, for example, will pay for the costly research and development program required for waste disposal? How will actual operating facilities be financed? Where will they be located? How should specific criteria for the disposal of all types of radioactive waste be developed? How will jurisdiction over the management and regulation of all forms of radioactive waste be shared between federal and provincial governments?

In the midst of the unresolved issues and uncertainties, one fact remains indisputable--a large and growing inventory of radioactive waste already exists in Canada. Long-term waste management is not, therefore, simply a philosophical or theoretical question; it is an unavoidable practical necessity.

REFERENCES

1. Aikin, A.M., J.M. Harrison, and F.K. Hare. The Management of Canada's Nuclear Wastes. Ottawa, Department of Energy, Mines and Resources, 1977. (Report No. EP-77-6)

2. Atomic Energy Control Board Advisory Panel on Tailings. The Management of Uranium Mill Tailings - An Appraisal of Current Practices. Ottawa, 1978.

3. Boulton, J. (ed.) Management of Radioactive Fuel Wastes: The Canadian Disposal Program. Chalk River, Ont., Atomic Energy of Canada Ltd., 1978. (AECL 6314)

4. Boulton, J., and A.R. Gibson, eds. First Annual Report of the Canadian Nuclear Fuel Waste Management Program. Chalk River, Ont., Atomic Energy of Canada Ltd., 1979. (AECL 6443)

5. Canada. Department of Energy, Mines and Resources. The Management of Wastes from the Nuclear Industry. Ottawa, forthcoming. (Energy Report Series)

6. Cluff Lake Board of Inquiry. Final Report. Chairman: Justice E. Bayda. Regina, Sask., 1978.

7. Nuclear Energy Policy Study Group. Nuclear Power: Issues and Choices. Cambridge, Mass., Ballinger Publishing Company, 1977.

8. Nuclear Energy Agency. Objectives, Concepts and Strategies for the Management of Radioactive Waste Arising from Nuclear Power Programs. Report by an NEA Group of Experts. Paris, Organization for Economic Co-operation and Development, 1977.

9. Royal Commission on Electric Power Planning. Chairman: Arthur Porter. Final Report. Vol. I: Concepts, Conclusions & Recommendations. Toronto, 1978.

10. Ontario. Select Committee on Ontario Hydro Affairs. The Management of Nuclear Fuel Waste. Final Report. Toronto, 1980.

THE STRUCTURE OF THE NUCLEAR INDUSTRY

This paper is based on a draft prepared by G.T. Leaist of the Electrical, Coal, Uranium and Nuclear Energy Branch of the Department of Energy, Mines and Resources and by E.F. Morisette of the Machinery Branch of the Department of Industry, Trade and Commerce.

November, 1980

Contents

BACKGROUND

Since 1952, when the initiative was taken to study the application of the reactor concept, the CANDU reactor design and the manufacturing and engineering capability supporting it have jointly evolved into a major world-class technology. That initiative was taken primarily by the federal government, acting mainly through its agencies Atomic Energy of Canada Ltd. (AECL), formed in 1952 from the National Research Council-administered laboratories at Chalk River, and Eldorado Nuclear Ltd., Canada's only uranium refiner.

A small group, including representation from Canadian electric utilities and industry, was set up at Chalk River in 1954 to study the feasibility of a nuclear power reactor based on natural uranium fuel and a heavy water moderator. The group confirmed the feasibility of the concept and recommended that a prototype facility be built. This step led to a unique reactor design with which Canada has since become identified - even the acronym CANDU, derived from the words Canada Deuterium Uranium, stresses its origin.

Procurement policies were developed at the engineering stage for the construction of the Nuclear Power Demonstration (NPD) plant at Rolphton and then the Douglas Point plant. These generally conformed with the policies of CANDU's primary customer and co-developer, Ontario Hydro. Previously, in developing hydroelectric and fossil-fuelled generating stations, Ontario Hydro had designed the plant, bought its components from competing suppliers, and managed its construction. These policies and procedures, extended into the nuclear power program, have resulted in a dispersed supply structure. While such a structure has the advantage of encouraging broad industrial participation in the domestic nuclear program, it is often viewed by potential export customers as a sign of lack of strength and capability to meet overall project requirements.

AECL works directly with provincial electric utilities in developing their power reactor requirements. It assumes responsibility for the detailed design of the nuclear steam supply system (NSSS) of stations and, as assigned by the provincial utilities, undertakes certain activities related to the procurement of components, such as setting specifications or evaluating tenders. In addition AECL, when requested, represents the utilities in Atomic Energy Control Board (AECB) licensing applications, prepares necessary documentation, and does related analyses. The detailed design and supply of components for the remainder of the nuclear steam plant (NSP), as well as for the secondary plant, (including the turbine generator) are provided in Ontario by Ontario Hydro together with manufacturers. In Quebec and New Brunswick such services are provided by private engineering and construction firms employed, respectively, by Hydro-Québec and the New Brunswick Electric Power Corporation.

Canadian utilities have always assumed the project management function themselves. With export sales, however, AECL has taken "turnkey"* responsibility for either the nuclear steam plant, as in Argentina, or the complete nuclear power station, as in Korea. The turnkey requirement in the international market place is typical of first-of-a-kind projects in developing countries.

In licensing the CANDU reactor design abroad, AECL might be expected, at least for the first units committed by the licencee, to seek major control over the supply of the reactor core and associated equipment, such as reactivity mechanisms. While AECL owns design specifications and other documentation, the use of which it can licence, manufacturing technology resides with Canadian industry. In supporting AECL design licencing initiatives in countries such as Italy and Romania, these companies have to decide whether to transfer their manufacturing technology to foreign firms by licence or sale. In general, Canadian manufacturers have been supportive, provided they are assured of equipment supply for one or preferably two reactor units along with the transfer of their technology, and of securing the domestic market against the possibility of imports from offshore licencees.

---

* A "turnkey" project is one which the builder turns over to the buyer completely finished. All the buyer then has to do is "turn the key" and operate the plant. The buyer does not take part in design or construction, therefore there is no transfer of technology.

The Canadian industry's approach to supplying components to nuclear power plants differs from that of the United States and other supplier countries. This difference arises primarily because of the structure and size of the Canadian nuclear industry and had its source in the commercial nuclear power program begun with the Douglas Point reactor. In other countries, the major manufacturing companies, such as Westinghouse in the United States or Siemens in West Germany, undertake both the design and the manufacture of a large part of the NSSS and the electrical generating plant (e.g., the turbine generator). These companies are well-established multinational manufacturers of electrical and steam-generating equipment and the world's electric generating utilities, have become accustomed to dealing with them. While some Canadian equipment manufacturers in the electric generating field have attained world recognition, none has achieved the international status of these foreign companies. While some suppliers of major CANDU components are subsidiaries of these firms, they lack the size and resources to accept total responsibility for designing and supplying the components of a nuclear reactor system.

The major multinational electrical equipment suppliers are perceived by purchasing utilities as having the management and financial resources to complete major projects and the longevity to service these projects throughout their nominal life. Without strong backing from their foreign parents, few of the smaller subsidiary firms in Canada are seen that way. A Crown corporation, which has the backing of government, can project to potential customers an image of capability, particularly when it has technological depth and a product with which good experience has been accumulated. As a result, a recent private sector study by The Task Force on CANDU Export Marketing concluded that "AECL should have the prime marketing and contracting function" (3).

Canada has achieved its good reputation in nuclear power for several reasons. It was in on the ground floor of reactor development and from the start had excellent research and development facilities and capability, which attracted enthusiastic and dedicated workers. The spirit of co-operation among AECL, the concept sponsor, Ontario Hydro, and the manufacturing industry was unequalled in programs elsewhere. Moreover, instead of dissipating its comparatively limited developmental resources on different reactor concepts as did many other countries, Canada concentrated on a specific reactor design. None of these conditions would have led to success, however, without the strong financial support and general assistance of government during the commercial development phase of the CANDU concept.

The nuclear manufacturing and engineering sectors make, in a larger context, several contributions to Canada's total industrial capability. They provide a highly sophisticated and unique technology, indigenous support for an important Canadian energy resource, and a potential source of high technology exports.

CANDU NUCLEAR POWER STATION EQUIPMENT

The main features of a CANDU power station are shown in Figure 1. The nuclear reactor building and all the equipment contained within it plus the related control room and reactor emergency systems make up the NSP. Within the NSP is the NSSS, shown schematically in Figure 2. Among the components of the NSSS are those which are uniquely identified with the CANDU system, such as the calandria, fuelling machines, and pressure tube assemblies, and those which are specially designed for CANDU requirements, such as steam generators and primary heat transport pumps. These components are illustrated in Figures 3 and 4.

The nuclear industry is normally identified with the equipment manufactured for the NSP, especially for the NSSS. The NSP accounts for about 50 per cent of the total cost of a station; the NSSS, about 15 per cent.

The nuclear power station outside the NSP is referred to as the secondary or conventional plant, the balance of plant (BOP), or most commonly the power generation system (PGS). Most of the equipment in the PGS can be found in other thermal electric generating stations. However, because of the relatively low pressure and high moisture content of the steam produced by the NSP, the design of the steam turbine for a nuclear power plant is different from that of a coal or oil-fired generating station.

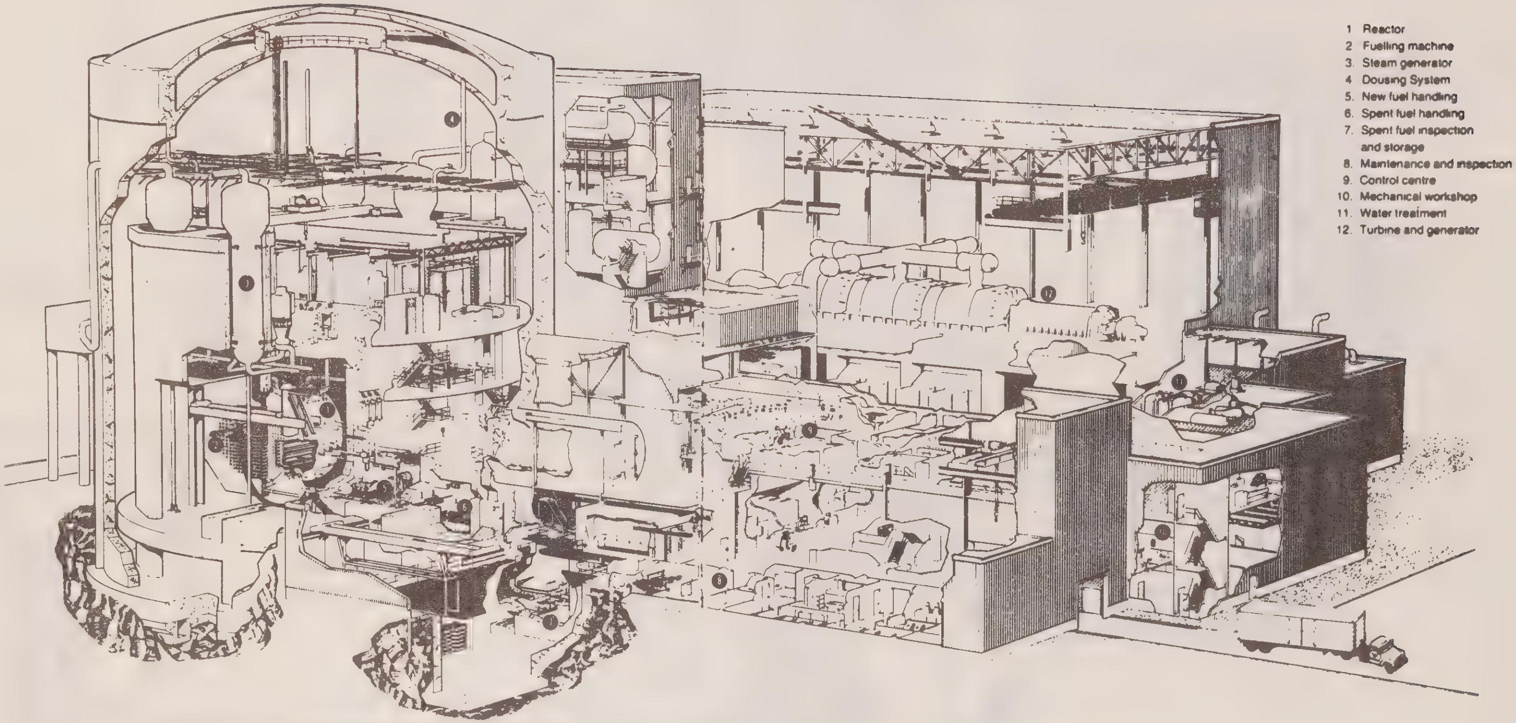
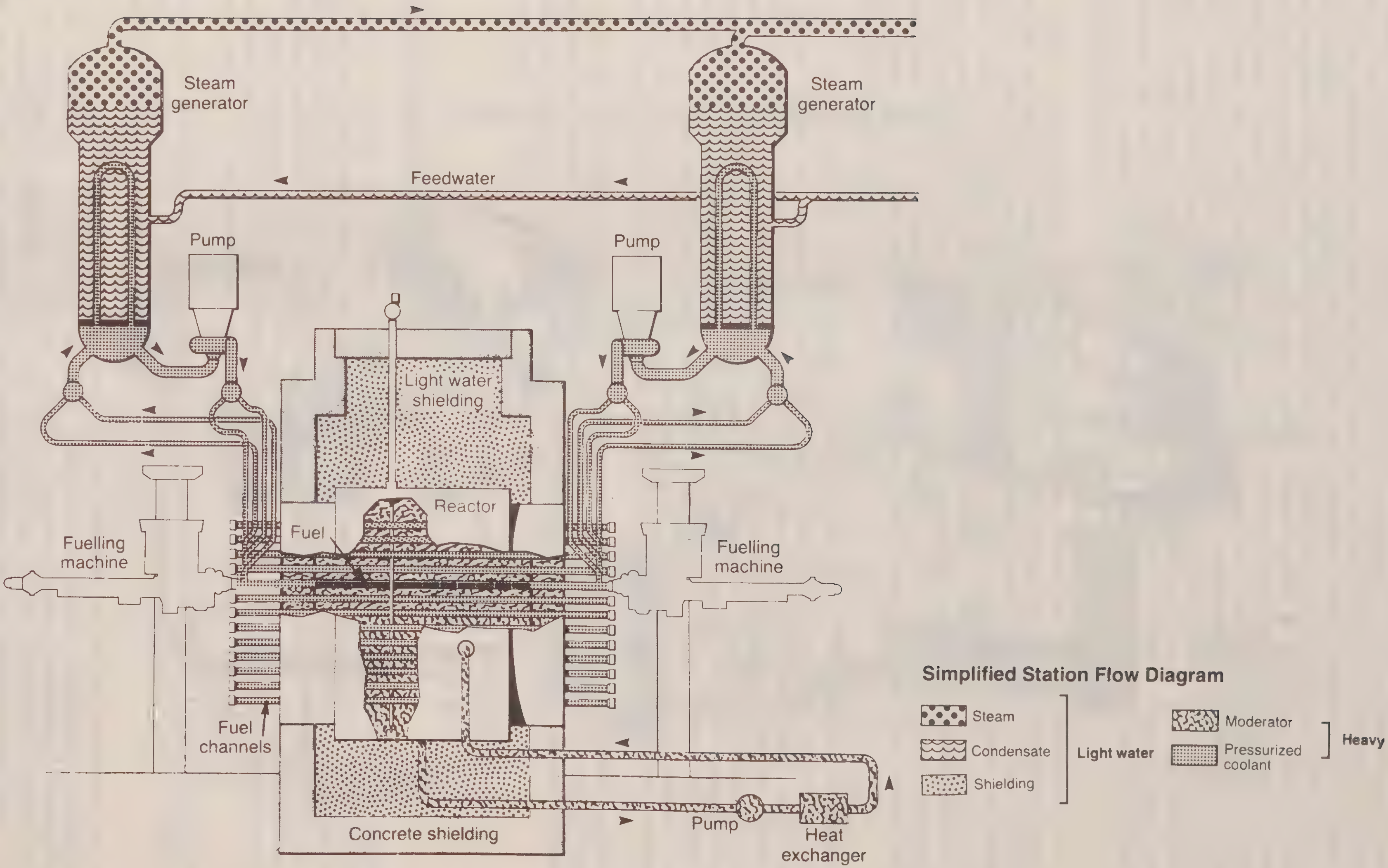


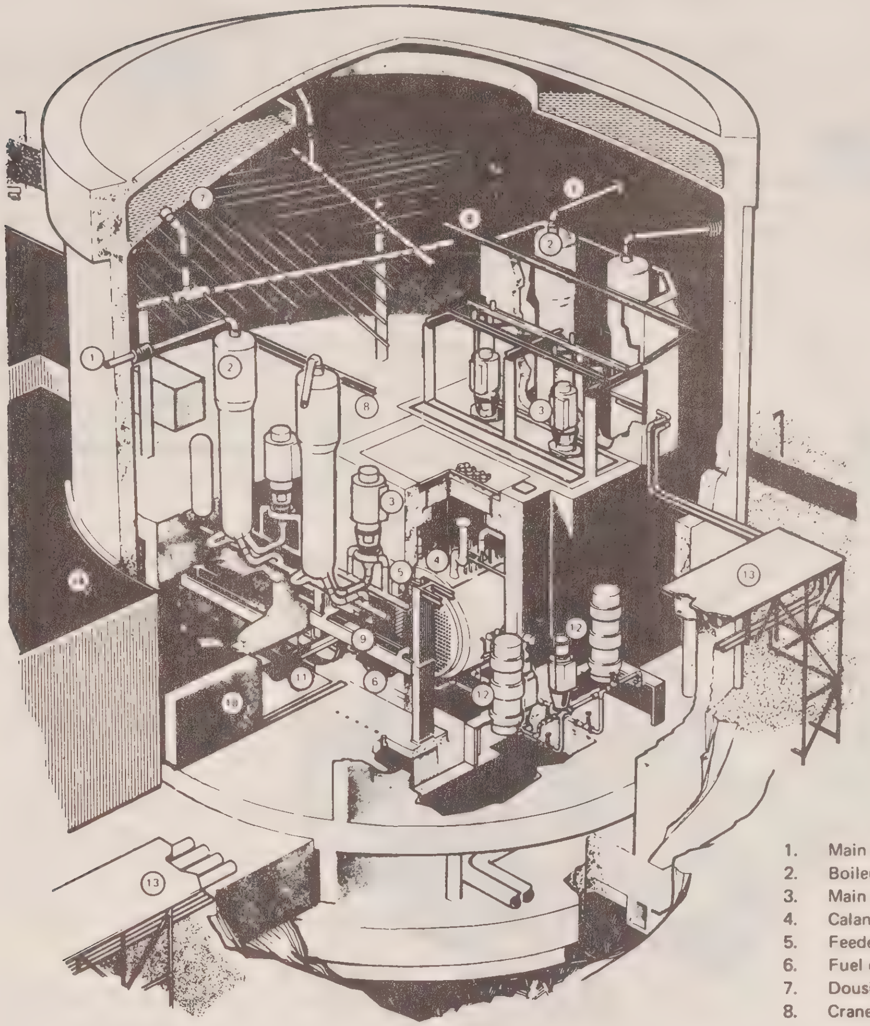
Figure 1: A 600 MW Nuclear Generating Station

Source: AECL



NUCLEAR STREAM SUPPLY STATION CANDU 600

Source: AECL



1. Main steam supply piping
2. Boilers
3. Main primary system pumps
4. Calandria assembly
5. Feeders
6. Fuel channel assembly
7. Dousing water supply
8. Crane rails
9. Fuelling machine
10. Fuelling machine door
11. Catenary
12. Moderator circulating system
13. Pipe bridge
14. Service building

Figure 3: The Reactor Building

Source: AECL

1. Calandria
2. Calandria shell
3. Calandria side tube sheet
4. Fuelling machine side tube sheet
5. Lattice tubes
6. End fittings
7. Feeders
8. Calandria tubes
9. Steel ball shielding
10. Annular shielding slab
11. Pressure relief pipes
12. Rupture disc
13. Moderator inlets (4 each side)
14. Reactivity control nozzles
15. Reactivity control devices
16. Horizontal flux detectors (9)
17. Poison injector nozzles (6)
18. Ion chamber cooling piping
19. End shield cooling piping
20. Calandria vault (light water shield)

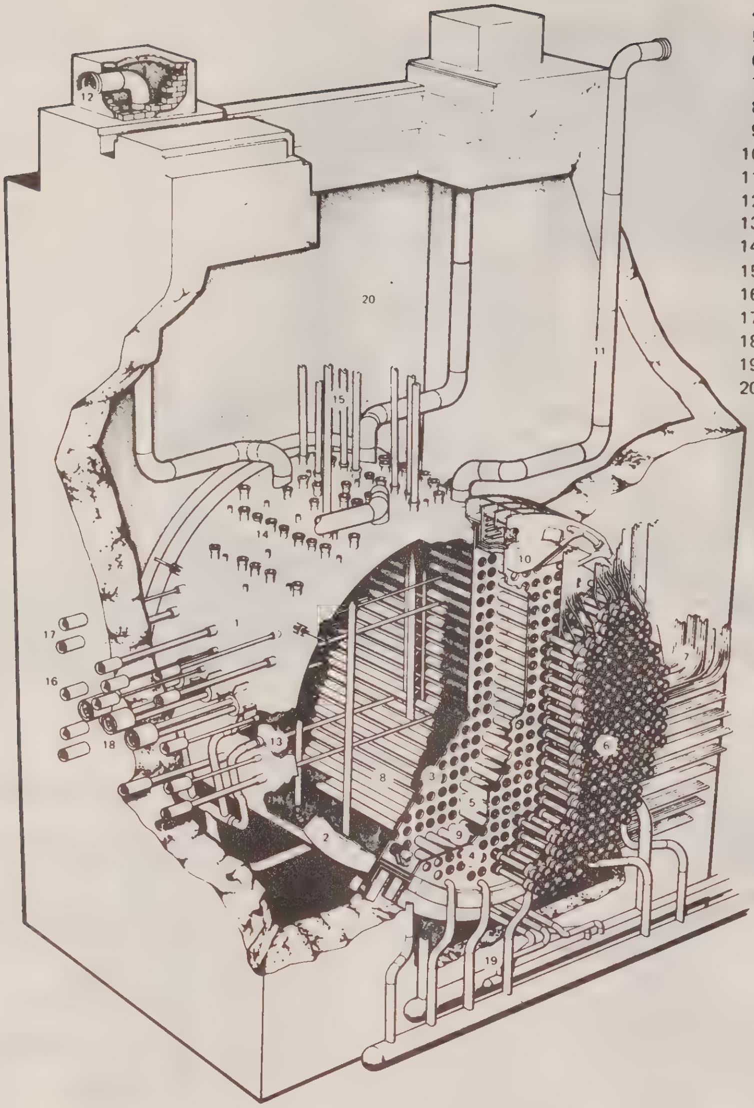


Figure 4: The Reactor Assembly

Source: AECL

STRUCTURE OF THE NUCLEAR MANUFACTURING INDUSTRY

The Canadian nuclear equipment industry embraces those companies that make the components of the NSSS and the PGS. They consitute a diverse group of companies, ranging from large, heavy-equipment manufacturers to small, skilled machining firms.

The major mechanical components of a NSSS include the calandria, pressure tube assemblies, the fuel handling system, the pressurizer, primary heat transfer pumps, steam generators, and nuclear valves. There are also the more conventional products such as heat exchangers, pipes, pumps, valves, vessels and so on. The current value of the NSSS components for a 600 MWe CANDU reactor is about $112 million, 75 per cent or more of which is spent in Canada.

Among the more than 100 companies that produce some item for a CANDU, about 60 can be considered main suppliers. However, the key components of the NSSS are made by 12 companies and, generally, for each component there are at least 2 manufacturers:

Calandria: Canadian Vickers, Dominion Bridge.

Pressure Tube Assemblies: Donlee Nuclear (end fittings), Chase Nuclear, Bristol Aerospace, Noranda (pressure tubes), Westinghouse Canada (calandria tubes), Bata Engineering (shield plugs).

Steam Generators: Babcock and Wilcox, Foster Wheeler

Fuelling Machines: Standard Modern Tool, Canadian General Electric

Primary Heat Transport Pumps: Byron Jackson, Bingham Willamette

Nuclear Fuel: Westinghouse Canada, Canadian General Electric, Combustion Engineering

Control Computer: Canadian Aviation Electronics

Turbine Generator: Howden Canada (Licencee of Brown Boveri Company), Canadian General Electric.

Ten of the 60 chief suppliers are located in Quebec and four of these companies - Dominion Bridge, Canadian Vickers, Canadian Aviation Electronics, and Velan Engineering - are important suppliers. Bingham Willamette, which makes pumps, is located in British Columbia, and Bristol Aerospace, a manufacturer of pressure tubes and calandria tubes is in Manitoba. The remaining 47 companies are in Ontario.

Of the chief suppliers, 20 per cent employ over 1 000 people; 10 per cent between 500 and 1 000; 40 per cent between 100 and 500; and 30 per cent under 100. The 20 per cent of companies with more than 1 000 workers have combined total sales (of all components) above $500 million.

About one-third of the companies are Canadian-owned; most of the rest are susidiaries of American, British, and Swiss companies. Among the key component suppliers, excluding those supplying sub-assemblies to the pressure tube assemblies, only Dominion Bridge and more recently Canadian Vickers are Canadian-owned.

Although the nuclear equipment sector represents only 5 per cent of the total activity in the machinery industry, it has one of the highest profiles. This stems from its contribution to Canada's energy supplies, its public image, and its advanced technology. The sector

employs directly over 6 000 highly-skilled workers (about 20 per cent of all the jobs in the nuclear industry) and indirectly about 17 000 people (1).

For manufacturers, the key characteristic of nuclear component processing is the application of an extremely high level of quality control standards. Such standards are required to meet not only the safety but also the reliability requisites of nuclear power plant operations. However, because the quality control procedures needed to satisfy those standards are usually well outside the normal experience of manufacturers, costly long-term upgrading programs have had to be undertaken.

Several other major characteristics of the industry are also noteworthy. Because of its special needs, the industry has had to invest in heavy front-end costs to develop and install sophisticated manufacturing facilities. It has had to carry major labour costs to develop and keep a skilled work force. From a long and costly learning process, the industry has acquired the expertise to make specialized components for the CANDU system, but those products have not been sold to other reactor suppliers because of their traditional buying patterns and the uniqueness of the CANDU technology.

While the nuclear industry demands dedicated facilities, few companies can manufacture exclusively for it. In fact, the heavy front-end investment combined with the procurement policies of utility companies tend to favour multi-product companies which can redirect resources to conventional production during periods of slow growth in the nuclear industry. As a result, most companies have several product lines, and the profitability of each product line is an important consideration in managerial decisions. Nuclear manufacturing work generally accounts for less than 15 per cent of the total production of a company and thus must compete within a firm for financial investment, managerial skills, and technical support.

The industry can make equipment and machinery for up to five 600 MWe reactors a year. In 1978, when activity reached its highest level in years, the industry operated at only 50 per cent capacity. A minimum level of activity is necessary to maintain the skilled labour force and the expertise needed to ensure a viable nuclear equipment manufacturing industry.

Except in periods of high industrial activity when shortages or delivery bottlenecks develop, the availability of most items used in the manufacture of equipment for a nuclear power plant (excluding zirconium and certain forgings and castings) does not constitute a constraint. The availability of skilled labour, however, can be a significant limitation, particularly since much of the technology is unique to the nuclear industry and has little or no application to other industries. The development of a skilled labour force to produce highly engineered nuclear components is normally spread over many years and is considered the key factor affecting the level of production.

The manufacture of large components such as steam generators and turbine generator sets requires from 500 to 1 000 workers. On the other hand, the making of many other components calls for only 30 or 40 labourers. But in each instance, the work force must be highly skilled.

Because of their size and subsidiary nature, most Canadian companies in the nuclear industry have limited engineering and development capability. The major investment requirements and the heavy front-end costs of developing manufacturing skills for nuclear components have favoured the subsidiaries of multi-product international companies. Yet in many areas, Canadian-owned companies are competing effectively. Specific examples of this are the fabrication of calandrias and the production of end fittings.

While some outstanding innovations and work have been achieved by Canadian manufacturers, AECL has provided the main engineering design and development reservoir for the nuclear power program. For the major components of the NSSS, AECL often provides the design and then works with the Canadian manufacturer to adapt it to the manufacturer's production capabilities.

STATUS OF THE INDUSTRY

In 1978 the Canadian nuclear industry was working on 10 units for the domestic market - Pickering B (4 units), Bruce B (4 units), Lepreau (1 unit), and Gentilly 2 (1 unit) - and two

for export to Argentina and Korea. At this peak level of activity, the industry worked at around 50 per cent capacity and generated direct employment for about 6 000 people. The value of nuclear equipment produced in 1978 was estimated at approximately $350 million.

A recent study of the nuclear industry commissioned by the Candian Nuclear Association estimated the total investment accumulated over the years by manufacturing companies at $214 million (1). However, in light of the nuclear industry's current prospects, no significant new investments are planned.

Beyond Bruce B and Pickering B, Ontario Hydro is committed to building a four-unit station at Darlington. The CANDU reactor units which are scheduled to begin service in the next decade are listed in Table 1.

Table 1
Reactor Units Scheduled for In-Service

Year	Reactor Units
1981	Lepreau 1, Gentilly 2
1982	Pickering 5, Wolsung 1 (South Korea)
1983	Pickering 6, Pickering 7, Bruce 5, Cordoba (Argentina)
1984	Pickering 8, Bruce 6
1986	Bruce 7, Romania 1
1987	Bruce 8
1988	Darlington 1, Romania 2*
1989	Darlington 2
1990	Darlington 3
1991	Darlington 4

*not yet committed

The equipment orders for these stations, except for the Darlington and Romanian reactors, have been with the manufacturers for some years, and the production of components is generally well advanced. It is expected that the component requirements for Darlington will not reach the shops for 2 or 3 years because of the long lead times needed for engineering, procurement, and receipt of the raw materials. After Darlington, reactor commitments in Canada are uncertain, and if the present low rates of economic growth persist, further reactor commitments are unlikely to be made in Ontario for at least several years.

Manufacturers are being asked to tender offers on components for the first CANDU reactor committed by Romania. As Romenergo of Romania is a licencee of AECL, it is at the same time seeking the transfer of manufacturing technology to Romanian companies. Except for the first unit now scheduled for completion about 1986, the timetable for future reactor commitments in the Romanian program is less certain and will depend upon the country's early experience, the availability of resources, and the need for more electricity. Although Canadian supply to the first, and probably the second, Romanian reactor should be substantial, from then on the Canadian manufacturing contribution will progressively and significantly decrease as Romanian capability expands.

While AECL was unsuccessful in the recent award by Argentina for its Atucha 2 project, which could have led to the company's participation in a program of four reactor units, AECL does have other export prospects. It has been studying, with a Japanese utility, the introduction into Japan of a CANDU generating station. It also has a licensing agreement with an Italian company which, together with the state electrical generating authority of Italy, has been considering the CANDU reactor. Further, AECL has had exploratory discussions with the Korea Electric Company. However, the prospect of CANDU projects in these countries cannot be forecast today with great confidence. AECL is also exploring other foreign markets, but they are at least two years away from commitment. The question of the export market is the subject of another in this volume: "Canada's Reactor Exports".

If no new orders for CANDU reactors are placed, the employment and capacity utilization prospects for the nuclear industry will become worse (Table 2). Only the committed reactors listed in Table 1 are taken into account in deriving the figures in Table 2.

Table 2
Employment and Capacity Utilization in the Nuclear Industry

	1978	1980	1983	1987
Employment	6 000	4 200	2 800	0
Capacity utilization	50%	37%	23%	0

As to profitability, the Canadian nuclear industry is now near the break-even point. A few companies that are sole suppliers or that have a unique product are making profits. The majority though, are either marginally profitable in their nuclear-related activity or, in some instances, losing money.

THE NUCLEAR CONSULTING SECTOR

Consulting capability for the nuclear industry has been developed for a broad spectrum of activities, among them uranium exploration and development, nuclear power projects, heavy water production plants, and related environmental matters.

The directory of the Canadian Nuclear Association lists 50 Canadian engineering consulting firms with an interest in nuclear power, while the directory of the Association of Consulting Engineers of Canada identifies 25 of its members as having nuclear expertise. Most of these firms are located in Ontario and Quebec and range in size from a few professionals to a total staff of about 1 000. Some offer services in a variety of engineering fields; others specialize in nuclear power. Total billings for private consultants in the nuclear field for 1977 have been estimated at between $30 and $40 million, providing employment for about 1 200 professional and technical workers (1).

The problems of private engineering consultants are related largely to the lack of opportunities in the nuclear power market both in Canada and abroad. Private consultants find little work in the domestic market (which has been concentrated in Ontario) because AECL and Ontario Hydro together perform nearly all the engineering services. Nuclear power projects in other provinces would provide much greater opportunities for these consultants, but the possibilities of this happening are limited, since only two commercial projects are currently being pursued outside Ontario, both of which are well advanced. In export markets, except for some relatively small contracts, the consultants have been wholly dependent upon the success of AECL, and when AECL has obtained projects consulting firms have generally participated only as subcontractors.

Because consulting work is conceptual and heavily oriented toward front-end design, it is usually the first in the nuclear industry to feel the brunt of a downturn in business. In the current nuclear market, the problems of consultants are compounded by limited opportunity and the low level of commitments to new projects. Without new orders for systems outside Ontario, the 1 200 people employed in 1977 in private nuclear consulting could fall to about 600 in 1979 and to about 180 in 1980 (1).

THE HEAVY WATER PRODUCTION SECTOR

Heavy water in the CANDU system permits the process of nuclear fission to occur efficiently and allows the use of natural rather than enriched uranium. It is the same chemically as ordinary water (H_2O), but the hydrogen in the water molecule is a heavy isotope of mass two, called deuterium. This isotope occurs naturally in all hdyrogen in the ratio of about 150 to one million.* A typical 600 MWe CANDU reactor, such as Gentilly 2 or Point Lepreau, requires an initial charge of about 480 tonnes of heavy water.

Heavy water production plants operate at three sites in Canada and together have a total nominal design capacity of about 2 400 tonnes a year, as shown in Table 3. If the production levels of the three plants averaged 70 per cent of nominal design capacity, 1 680 megagrams of heavy water would be available each year. That amount is sufficient for the initial charge of about 1 500 MWe of new CANDU power reactor capacity a year.

Table 3
Heavy Water Production in Canada

Location	Nominal Capacity
Nuclear Power Development, Bruce County, Ont. (Ontario Hydro)	
BHWP-A	800 tonnes a year
BHWP-B	800 "
Glace Bay, N.S. (AECL)	400 "
Port Hawkesbury, N.S. (AECL)	400 "

* All Canadian heavy water production plants use the Girdler-Sulphide process. In this process, heavy water, which occurs in natural water, is concentrated to at least 10 per cent by a series of exchanges of deuterium between hydrogen sulfide and water. It is then concentrated further by vacuum distillation to above 99.7 per cent heavv water, which is the reactor grade product.

Because of a forecasted decrease in demand for heavy water, Ontario Hydro cancelled the BHWP-C plant and in 1979 decided to mothball the partially completed BHWP-D plant, scheduled to begin service in 1981. For the same reason, the federal government mothballed AECL's partially built heavy water plant at Laprade, Quebec.

Heavy water plants are capital intensive. Because of the negative experience of the two Nova Scotia plants, their capitalized costs provide poor guidance to the cost of a new plant today. More meaningful cost data are obtainable from Ontario Hydro's experience with its Bruce plant, which suggests that, in addition to the price of land or steam generating facilities, an 800-tonnes-a-year heavy water plant would cost $530 million in 1979 dollars. This amount is about half the all-inclusive cost of a 600 MWe nuclear power plant, but a large heavy water plant, such as one designed to produce 800 tonnes a year, could supply the heavy water needs of one additional nuclear power plant of 600 MWe capacity each year.

Heavy water is not consumed in a nuclear plant, though some replacement (about one per cent a year) is needed to cover losses from leaks, etc. Heavy water demand is therefore dependent not upon the number of CANDU reactors in operation, as in the case of uranium demand, but upon the rate at which new reactors are committed. Heavy water supply from currently operating plants should be sufficient to meet the demand from domestic and export market projections for CANDU reactors in the 1980s. Thus the prospects of new heavy water plant commitments in Canada, especially with mothballed plants such as BHWP-D in the wings, are practically nil. Even with the present plants, a surplus may be generated.

DISCUSSION OF ISSUES

To generalize, the Canadian nuclear equipment industry is fragmented, concentrated in Ontario and Quebec, comprised of many small companies, short of R&D and engineering capability, and controlled largely by foreign interests. In a word, it is typically Canadian. Yet this conglomeration of companies, headed by AECL and the utilities, has produced a competitive reactor system. Industries of other countries possessing far greater financial and human resources have failed in similar attempts to develop nationally-sponsored reactor systems.

The current problems of the industry are twofold: it lacks both projected orders and an industrial identity. In just four years, from 1974 to 1978, the industry's outlook has changed from highly optimistic to deeply uncertain. Its dismal near-term prospects are shared by other nuclear suppliers in all Western countries except France, the only non-communist country now sustaining a major, comprehensive nuclear power program.

Two studies of the Canadian nuclear industry were made between 1974 and 1978. The first study, prepared in 1974 by the Department of Industry, Trade and Commerce in co-operation with AECL and the Department of Energy, Mines and Resources, "examined the impact of nuclear equipment and services on Canadian industry's ability to meet domestic nuclear power requirements"(2). The second was sponsored in 1978 by the Canadian Nuclear Association and was titled Economic Impact of the Nuclear Energy Industry in Canada (1). Whereas the 1974 report was concerned with whether there would be sufficient industrial capacity to meet the growing domestic and export demand for CANDU reactors, the 1978 report dealt with the declining prospects for the industry. In the few years between reports, the domestic nuclear power forecast for the year 2000 had plunged from various earlier estimates of up to 130 000 MWe to 45 000 MWe. And exports always seemed to be just another year away.

Perhaps if Canada had accepted the U.S. light-water reactor design, which predominates in world markets, Canadian industry would be better placed to get export orders for components. But the world nuclear industry has excess productive capability, and with their large, modern facilities are better able to capture the available component market. Canadian industry has benefited from its virtual monopoly on supply to CANDU reactors in both domestic and foreign markets. Moreover, unlike the gas-cooled reactor of the United Kingdom, which could suffer in development because of a lack of major international partnerships, the CANDU reactor is water-cooled, like its chief light-water competitors, thus allowing the Canadian nuclear industry to benefit from a global fund of somewhat similar technology, to which it also contributes.

The industry maintains that it can survive and probably make marginal profits if customers order, on average, about two reactors a year. Other commentators would put the "survival number" somewhat lower. Whatever the figure, failure to maintain it would force some companies to abandon the nuclear business, particularly if more profitable or less demanding lines of production can be found. Once hurt financially, these companies will be less likely to return to the business unless the terms of trade were improved. If a sizable number of main component suppliers were to leave the nuclear market, the vigour with which the CANDU reactor could be promoted in export as well as domestic markets would seriously degenerate. For this reason, and in light of the downturn in domestic prospects, the continued participation in the Canadian reactor programs of countries such as Romania, Argentina and Korea is vitally important to the future of the industry and the CANDU reactor.

At present Canada does not have control over essential nuclear materials such as valve forgings and zirconium, which are supplied from abroad by quasi-monopolists. This could constrain the development of Canadian export markets.

The fall in market prospects has also contributed to an identity crisis within the industry, which would not have emerged if business had been brisk. Because of the fragmented structure of the industry, many companies feel helpless to exert control over their future, which, given the weak domestic market, is being determined by AECL's success in foreign sales. On the other hand, the industry has been shielded from the demands of the international market place by the primary risk-taker - AECL.

The conclusion of the industry's 1978 Task Force on CANDU Export Marketing that "AECL should continue to have the prime marketing and contracting function" was conditional on the participation of the industry in the process. Such participation requires the formation of a representative group capable of speaking and making commitments for the industry. To this end, a new entity called The Organization of CANDU Industries (OCI), which represents the private sector, has been formed.

If the industry is to participate effectively in the marketing and negotiating of international projects, it must be prepared to accept some of the attendant costs and risks. None of the manufacturing companies that supply nuclear components have negotiated with foreign buyers for sales on the scale of nuclear power plants. Further, some Canadian companies are subsidiaries of AECL's foreign competitors. Nevertheless, a well-organized manufacturing industry with good leadership would offer a more comprehensive Canadian approach to nuclear markets and could help greatly in selling CANDU reactors.

The fact that many of the nuclear manufacturing companies in Canada are subsidiaries of U.S. firms could lead to political difficulties should Canadian nuclear policies diverge significantly from those of the U.S. Confrontations with the U.S. over nuclear issues have been avoided. However, relations between Canada and the U.S. on nuclear matters are becoming more formal, partly because of the many personnel and organizational changes, and partly because of the diffusion of responsibilities for nuclear matters in the U.S. executive branch departments and agencies.

The idea of transferring AECL's Engineering Company to the private sector has also been raised. The company employs about 2 000 workers and serves as the focal point of Canada's nuclear industry. Private engineering companies, particularly when faced with a decreasing demand for their services, eye with envy the role of the Engineering Company. However, Ontario Hydro has been gradually moving more of its design work to its own office and will do most of the design outside the reactor core area for the Darlington station. Also, without enough export orders, the Engineering Company could have difficulty maintaining its current level of employment. If Ontario Hydro believed that the privatization of the Engineering Company were about to happen, it might transfer more of the engineering design and procurement activities to its own operations. Such a move would fragment the industry further, thereby making it less attractive to export customers.

Canadian utilities, Ontario Hydro in particular, have operating and construction experience that is well recognized worldwide. Ontario Hydro has assisted in the training of staff to operate AECL-supplied reactors offshore and occasionally co-operated in marketing efforts, but it is somewhat constrained by its mandate, especially if risks outside Ontario are involved. However, a marketing organization comprising industry, Ontario Hydro, and AECL

would constitute a formidable team. Some countries might be prepared to pay a premium to obtain access to the full slate of nuclear know-how, from research and development to plant operation and maintenance. This is one of a number of marketing strategies which might make the CANDU reactor more attractive to potential foreign buyers.

In summary, the Canadian nuclear industry's major problem is the current lack of a vigorous domestic market. Export orders could provide some relief, but because of stiff international competition, these are hard to get. Moreover, because of their scale, nuclear exports involve substantial national involvement and some political as well as commercial risks. Nevertheless, heavy involvement in the nuclear power programs of three countries would do much to alleviate the depressed state of the industry. A contract with one of these countries, Romania, has been obtained and will need nurturing. Because of the industry's nature, there is no easy solution to its identity problem, though some progress is being made. Finally, because of Canada's growing dependence upon nuclear energy, a survey of components critical to the CANDU system and produced outside the county might be undertaken to determine Candian vulnerability to foreign influence and possibly to help achieve greater economic independence.

References

1. Leonard & Partners Ltd. Economic Impact of Nuclear Energy Industry in Canada. Toronto, Canadian Nuclear Association, 1978.

2. Department of Industry, Trade and Commerce. Canadian Nuclear Industry Study, Ottawa, 1974.

3. The Task Force on CANDU Export Marketing. A Report by the Task Force on CANDU Export Marketing. Chairman: J.M. Douglas. Ottawa, 1978. (copies available from the Department of Industry, Trade and Commerce, Ottawa).

CANADA'S REACTOR EXPORTS

Written in the summer of 1980 by R.W. Morrison, reviewed by the Uranium and Nuclear Energy Branch, EMR and by other federal departments and agencies, and revised in the Fall of 1980. Parts of it are based on earlier drafts by A. Aikin and G.T. Leaist.

February 1981

TABLE OF CONTENTS

INTRODUCTION

Canada's exports of nuclear equipment and technology represent both a natural extension of, and a support for, the domestic nuclear power program. Canada's efforts to market the CANDU abroad have always been closely related to this domestic program. This differs from the situation of Canada's other principal nuclear export, uranium, where the export market has been and remains the dominant factor. Some aspects of reactor exports, such as Canada's policy on non-proliferation and the structure of the domestic industry are dealt with in others in this volume.

CANDU exports benefit Canada in several ways. They provide scale and continuity of orders for the domestic nuclear manufacturing industry, and spread the costs of research and development over a larger market. They also provide foreign exchange for Canada and enhance its status as an industrial country capable of supplying large-scale high-technology systems rather than as a purveyor of natural resources only. CANDU exports could help to reverse this trend.

Reactor exports also have risks associated with them, some of which are common to many large-scale international projects. They may be subject to commercial losses, or to disruption when political regimes change, as was the case for the French and German reactor projects in Iran. They involve the vendor country in long-term co-operation with the recipient, which could cause problems if either partner were to change its policies or commitments. Finally, they are complicated by the potential for diversion of fissile materials from the civilian nuclear fuel cycle for military purposes.

Canada believes that on balance the benefits outweigh the risks, and that making reactors available for peaceful purposes to those countries willing to accept strict international safeguards is generally the best way to proceed. Denial of this important energy technology could embitter international relations and lead countries to acquire facilities which are completely free of international control: there are risks involved in not selling reactors also.

THE CANDU AND OTHER FUEL CYCLES

In any discussion of nuclear reactor exports it is important to understand the uniqueness of the reactor system and the associated nuclear fuel cycle on which Canada's domestic nuclear program is based. The reactor is the CANDU (CANada-Deuterium-Uranium), fuelled by natural uranium, and moderated and cooled by heavy water.* Natural uranium contains only 0.7 per cent uranium-235, the fissile isotope of uranium. The remainder is U-238. Because of this low concentration of fissile material in its fuel, the CANDU is designed to use neutrons from the fission process very efficiently in maintaining the fission chain reaction which is the source of the energy in a nuclear reactor.

Heavy water is used to moderate, or slow down, neutrons from fission in order to make them more effective in inducing further fission in fissile nuclei. It is more effective than the light water or graphite moderators used by the other commercial reactor systems. The use of heavy water, coupled with careful design for neutron economy, makes the use of natural uranium possible in the CANDU. It also makes for high efficiency of uranium utilization.

Another salient feature of the CANDU is its use of pressure tubes containing fuel channels and pressurized heavy water coolant. These run horizontally through the volume of the moderator, and permit the fuel bundles to be pushed through on a continuous basis, thus allowing for on-power refuelling without shutting the reactor down. Light water reactors (LWRs) are enclosed in a single large pressure vessel and once-a-year refuelling is done by shutting down the reactor for a few weeks and opening the pressure vessel.

---

* Heavy water is deuterium oxide, or D_2O. Deuterium is a heavy isotope of hydrogen.

The American-designed LWR is the dominant system in the world, constituting about 90 per cent of the world's stock. The LWR requires enrichment of the fissile content of the uranium (the U-235) to about 3 per cent; use of LWR systems is thus contingent upon the availability of enrichment services. Originally, these could be obtained commercially only from the U.S.A. This led to fears by many countries in the early 1970s that enrichment might not be available to them, or might be available only on politically unacceptable terms. As a result, enrichment services were established in the U.S.S.R. and a few European consortia. There is now a glut of enrichment capacity in the world, but many countries are still concerned about their dependence on foreign sources.

Both the CANDU and the LWR currently operate on the once-through fuel cycle. The uranium fuel is run through the reactor once and the used or spent fuel then stored. Of the potential fission energy in the uranium fuel, only about 1 per cent is actually burned: most of the U-235, and some of the plutonium-239 which is created in the reactor by neutron bombardment of U-238.

Upon discharge, spent LWR fuel contains more U-235 than the natural concentration of 0.7 per cent. LWRs were originally sold with the idea that the full fuel cycle would be implemented, including reprocessing and recycling of uranium and plutonium from the spent fuel. Financial credit was allowed for the hypothetical value of the fissile material. This was not the case for the CANDU.

Canada has sufficient uranium resources to support its nuclear power program on the once-through cycle well into the next century, and still have ample uranium left over for export. Other countries less well endowed, especially Japan and the larger industrial countries in Europe, are seeking to use a much greater fraction of the potential fission energy contained in natural uranium.

Advanced fuel cycles which will allow a much greater proportion of the potential fission energy of uranium to be used are under study. Most other industrial countries are keenly interested in the fast breeder reactor, which is very different from the LWR or CANDU. This reactor creates more fissile material than is actually burned in the reactor by converting U-238 to Pu-239. The plutonium is then separated chemically from the spent fuel and recycled into fresh fuel. This permits a large extension of the energy available from a given amount of natural uranium, and permits much greater security of supply for countries which lack their own uranium resources. It also extends greatly the range of lower-grade uranium resources which could be economically exploited. However, the price of natural uranium would have to rise dramatically before advanced fuel cyles would be justified economically.

Thorium, which is about three times as abundant in the earth's crust as uranium, can also be converted to another fissile isotope of uranium (U-233) by neutron bombardment. This is feasible in a CANDU without great need for modification to the reactor itself, although of course facilities for separating and recycling the U-233 would be required. Thus the CANDU offers an advanced fuel cycle option which requires considerably less innovation than the fast breeder.

Most of the other industrial countries (U.S.A, France, Germany, Japan, Sweden, Belgium, Spain, Italy), as well as newly industrializing countries, have selected the LWR as the foundation of their nuclear power programs. In most cases, the LWRs were obtained under licence from U.S. firms, but several countries, notably France and Germany, have developed an independent capability to manufacture LWRs and to export them.

The LWR is thus a formidable competitor for the CANDU. It is built and exported by major industrial powers, several of which have a reputation for excellence in technology. Most of the other exporting companies are industrial conglomerates with previous experience in electric power projects and most have a larger domestic market than Canada's. They have marketing organizations around the world, and can offer a wide range of products and services. The LWR tends to have the advantages of standardization and economies of scale, while also providing customers with a diversity of suppliers. Purchasers of the CANDU system are initially dependent on Canada for the nuclear technology. The LWR strongly influences licensing, safety, and regulatory criteria around the world and a great deal is known about its performance in a variety of situations.

Nonetheless, the CANDU has a number of features in its favour. Its use of natural uranium means that a country is able to maintain a greater degree of autonomy in its nuclear program than if it is dependent upon enrichment services. Much of the technology associated with the CANDU can be transferred to countries with a relatively less developed industrial capacity. The CANDU has accumulated a remarkable performance record for economy, safety, and reliability in Ontario. In terms of lifetime gross capacity factor, by which the world nuclear industry measures performance, six of the world's top seven reactors in 1979 were from the Ontario CANDU system. The CANDU is cost-effective, especially in multi-unit stations, because of its lower fuelling cost and higher availability factors. It makes more efficient use of uranium on the once-through cycle than any other thermal reactor. It can be modified to run on thorium, which would extend nuclear resources considerably. There is no technical problem in obtaining lifetime supplies of both uranium and heavy water for the CANDU. Canada can provide both.

The advantages and disadvantages of the CANDU will be discussed further below. It should be noted though that while the CANDU has many technical and economic advantages, there are broad institutional and political aspects of the LWR position in world markets which may continue to be difficult to overcome.

ROLE AND CURRENT STATUS OF THE DOMESTIC NUCLEAR POWER PROGRAM

The domestic nuclear power program clearly offers many advantages to Canada. It provides an essentially autonomous system for generating electricity which makes use of Canadian resources and Canadian technology. It is cost-competitive with coal in most parts of the country, especially in Ontario and Quebec. In 1979, nuclear reactors generated 30 per cent of the electricity in Ontario, saving about $400 million in foreign exchange costs for imported coal. At 3¢ per kilowatt-hour, Ontario's nuclear electricity is worth about a billion dollars per year.

Although the benefits of the domestic nuclear power program have always been considered its principal raison d'être, exports have also been viewed as a natural extension of the program since its inception. They were considered essential to give the program the scale necessary to bring adequate returns on investment in R&D, to ensure the competitive worth of the CANDU system and demonstrate that worth to Canadians, to support the Canadian nuclear manufacturing industry through periods of slack orders, and to symbolize Canada's competence in high technology.

In 1974 and 1975, it looked as if the Canadian industry would be hard-pressed to meet export orders. Projections made by the federal Department of Industry, Trade and Commerce (IT&C), and Atomic Energy of Canada Ltd. (AECL) suggested that there might be 130 000 MWe of nuclear electrical capacity in Canada by 2000. The industry was considered capable of building at least three units a year. Domestic orders were expected to come in at the rate of four per year and one export order per year was seen as possible. Heavy water was also in fairly short supply and there was concern that not enough would be available for the domestic program, let alone for export.

Since that time, due to the decrease in projected electricity demand and lack of domestic orders the nuclear manufacturing industry in Canada has developed considerable overcapacity for reactor and heavy water supply. Most of the other vending countries also have excess capacity in their reactor industries. Not only is there ample capacity for the export of reactors, but such exports are seen by some as essential for the Canadian nuclear industry to survive in its present form in the 1980s. Every successful reactor export brings in several hundred million dollars in foreign exchange, helps to provide economies of scale, maintains employment and technological capability, and enhances morale within the industry and credibility with the general public.

The current status of the domestic program is shown in Table 1. Currently operating Canadian nuclear reactors are entirely in Ontario (four at Pickering and four at Bruce, in addition to smaller reactors at Rolphton and Douglas Point). The total nuclear electric generating capacity in Canada in 1980 is about 5 200 MWe.

There are fourteen large CANDU reactors under construction or committed in Canada with a combined generating capacity of 9 840 MWe. Twelve of these are in Ontario - four each at Pickering, Bruce, and Darlington, one at Gentilly in Quebec and the other at Point Lepreau in New Brunswick. The total capacity of operating or committed reactors in Canada is thus about 15 000 MWe.

The CANDUs at Point Lepreau and Gentilly represent the standard 600 MWe version which has been selected for export. Units of this type have been purchased by Argentina, Korea, and Romania.

NUCLEAR POWER DEVELOPMENT IN CANADA

The seeds of Canada's nuclear power program were sown during the Second World War when the NRX research reactor was designed to produce plutonium for the Allied War effort and to perform basic research on nuclear physics. NRX used a natural uranium fuel and heavy water moderator and became operational in 1947. A second, larger heavy water research reactor, NRU, went into service in 1957.

The Canadian nuclear power program began in earnest in 1954 when the federal government (through AECL) and Ontario Hydro jointly undertook a feasibility study which led to a 22 MWe nuclear power demonstration reactor (NPD). The federal and Ontario governments have been instrumental in the program ever since.

Because of the experience already accumulated in Canada with heavy-water natural-uranium systems, and because of the desire to avoid dependence on foreign sources of enrichment, it was decided to use heavy water and natural uranium for power reactors as well.

The contract for design and construction of NPD was awarded to Canadian General Electric (CGE), in line with the federal government's original intention to create a private sector capability for designing and building nuclear reactor systems.

While NPD was still under construction in 1959, it was decided to go ahead with a 200 MWe reactor at Douglas Point, the first to be called by the generic name CANDU. Despite AECL's efforts to develop an independent nuclear capability in Canadian private industry, AECL took over the design and project management of CANDU at this point, as Ontario Hydro was unwilling to commit itself to a private designer/supplier in a monopoly position. This left private industry in the role it has occupied ever since, that of manufacturing components and providing engineering services for reactors designed by AECL. Ontario Hydro, and later the public utilities in Quebec and New Brunswick, took over project management for subsequent reactors built in Canada.

NPD started up in 1962 and functioned reasonably well. Although there was still no operating experience from the much larger Douglas Point reactor, the Ontario and Canadian governments announced in 1964 that a nuclear station consisting of two 500 MWe units would be built at Pickering with provision for two additional units ordered in 1967. Douglas Point went critical in 1966 but experienced difficulties for a number of years.

The Canadian and Quebec governments agreed in 1966 to construct a reactor, Gentilly I, which would be heavy water moderated and light water cooled. Despite active interest on the part of CGE in an alternative CANDU design, this experimental reactor, which has never achieved satisfactory operation, was built by AECL. This appeared to confirm that it was government policy to exclude private sector vendors from the domestic market, even outside Ontario.

EARLY EXPORTS

Meanwhile, Canada's efforts had not gone unnoticed internationally. India had expressed strong interest in nuclear power ever since its independence in 1947. The Indians were interested in the potential for autonomy offered by the natural-uranium heavy-water system.

TABLE 1
Canada's Domestic Nuclear Power Program

Reactor or Station	Capacity, MWe	Ordered	Operational
NPD	22	1955	1962
Douglas Point	200	1959	1966
Pickering A 1,2	4 x 515	1964	1971
3,4		1967	1972-73
Bruce A	4 x 746	1969	1977-79
Gentilly II	637	1973	1983
Point Lepreau	630	1974	1981
Pickering B	4 x 516	1974	1982-84
Bruce B	4 x 756	1975	1983-87
Darlington	4 x 881	1978	originally 1984-87 now 1987-91

They had some uranium of their own and also abundant thorium. In 1956, Canada offered to build an NRX-type research reactor for India as technical assistance under the Colombo plan. This was considered at the time to be an exemplary gesture, as nuclear power was universally viewed as one of the bright hopes for future energy supply, and one that should be shared with developing countries. Canada had already assisted with hydraulic projects in the region, and nuclear power seemed like a logical extension of its technical co-operation. Known as CIRUS (Canada - India - Reactor: the US reflects the use of U.S. heavy water for this project), this research reactor later furnished the plutonium for India's nuclear explosion.

In 1963, Canada agreed to assist India in the construction of a 200 MWe power reactor similar to Douglas Point. A second unit was sold in 1967. These became known as RAPP-1 and RAPP-2. The Indian Atomic Energy Commisssion acted as project manager. Montreal Engineering Ltd. acted as procurement agent for Canadian goods and services, and AECL provided design and engineering services.

The Indians acquired, about the same time, a 2 x 200 MWe light water station, Tarapur, from the United States. India has gone on to build its own 200 MWe CANDU-type reactors at Kalpakkam and at Narora, two units at each site.

Shut out of the domestic market by the Ontario Hydro decision to deal directly with AECL as designer, CGE decided to try to sell CANDUs in the export market throughout the early 1960s. They sold a 137 MWe unit to Pakistan in 1964, with some help on concessional financing from CIDA. This project went reasonably well, but it was their last sale. They spent over 2 years marketing in Finland, but in the end were unsuccessful because of the involvement of the

U.S.S.R. In Argentina, which had decided to adopt a natural-uranium heavy-water system because of its possibilities for autonomy, CGE lost to a German competitor, largely because of the greater government support it appeared to have. Sales efforts were underway in Italy, Yugoslavia, and Romania in the spring of 1968, when CGE decided to withdraw from the export marketing field and to concentrate on supplying components. Lack of proven experience in the domestic market resulted in difficulties for CGE in its export sales efforts.

THE MARKET AND THE COMPETITION BEFORE 1968

Canada has been almost unique in staying with a single reactor concept from the start. The Americans pressed on with two designs of light water reactor originally conceived for their nuclear submarine program. American designers were free to draw on many light water concepts, as facilities for enriching the uranium were available from the American military program. The pressurized water reactor (PWR) designed by Westinghouse and the boiling light water reactor (BWR) designed by General Electric have become the dominant reactor systems in the world.

The British and the French began with gas-cooled reactors using natural uranium fuel and graphite moderator. The British have continued to base their program on gas-cooled reactors of a more advanced design, the Advanced Gas-Cooled Reactor (AGR), although they have announced plans to order PWR's under Westinghouse licensing starting in 1982.

A number of countries, including Sweden, Switzerland, France, and Germany have pursued designs of heavy water natural-uranium power systems. Of these, only Germany has built a commercial-sized plant, and this was in Argentina rather than in Germany. This heavy water reactor, Atucha 1, uses a pressure vessel rather than pressure tubes as in the CANDU. Britain and Japan have built, and Italy is now building, prototype reactors fuelled with enriched uranium which use heavy water moderator and light water cooling (somewhat similar to Gentilly 1), but these have not been brought to the commercial stage. Eventually all these countries except the U.K. adopted the light water reactor as the basis for their programs, and the U.K. now seems to be moving in that direction too.

In the 1950s and early 1960s there was great confidence in the eventual feasibility of nuclear power, but it was not yet clear at what point it would become competitive with fossil fuel-fired power. Utilities were reluctant to commit themselves before they could perceive an economic advantage. Given the long lead times required to develop a nuclear power program, it would also be some time after making a commitment that they could be certain of the results.

In the export market, the U.K. was first off the mark with sales of its gas-graphite reactors to Japan and Italy in the late 1950s. In the same period, France sold a gas-graphite reactor to Spain. However, there has been no follow-up to these early successes. After the Suez crisis it was believed that the European market would develop first because of that continent's exposure to the risk of oil shortages but it was in the United States domestic market that the first big breakthrough of orders occurred. This was in the period 1964 through 1967, when 50 000 MWe of nuclear generating capacity was ordered. (At the end of 1979 installed capacity in the United States just reached 50 000 MWe). It was claimed that nuclear power could be competitive with coal-fired power even in the heart of American coal country.

The surge of American orders had a dramatic impact on nuclear policies around the world. The other industrial powers, anticipating that the LWR would become the world's mainstream nuclear power system, wanted to participate in its development. Their utilities sought the benefits of economies of scale and technological security that would come with the leading system. Their nuclear industries wanted to be able to build and sell what at the time seemed to be the most promising reactor. The perception became self-fulfilling as country after country decided to adopt the LWR in the late 1960s and early 1970s. Eventually all the leading Western industrial countries except the U.K. and Canada selected the LWR as the basis of their nuclear programs.

Despite a relatively early start in ordering commercial-scale power reactors, Canada was left behind in the stampede toward the LWR. It is interesting to note that both the American and other foreign decisions to order LWRs were based on expectations of cost and performance,

rather than proven operating experience. Confidence in American technology, and in the judgement of the larger American utilities, seems to have been sufficient. In Canada's case, no such act of faith was forthcoming. Douglas Point was still having its teething troubles, and it was several years before the excellent performance record of the 500 MWe CANDUs at Pickering was established in the years 1971-73.

AECL came into the market at a difficult time. The industrial powers were swinging toward the LWR. The smaller industrial countries and the newly-industrializing developing countries were entering the market very tentatively, and were cautious about committing themselves to a system, which was then unproven, from the smallest of the nuclear supplier countries.

CANDU MARKETING UNDER AECL - 1968 TO THE PRESENT

After CGE's withdrawal from the export market in 1968, AECL was assigned responsibility for reactor exports. This was the second area originally intended for private industry that AECL had absorbed, and it was soon to become involved in a third: heavy water production. There were valid reasons in each case, but together they made for a fairly rapid expansion in the range of AECL's interests, well beyond its original research and development mission.

It seemed obvious that Canada should continue to be involved in the reactor export market. Exports were still desirable for economies of scale, technological prestige, foreign exchange, and support for the domestic program, and perhaps even political influence. AECL had the design expertise and Canadian industry and Ontario Hydro had the experience of building reactors in the domestic market. Strong national government support would be required in any export drive, therefore it seemed reasonable for the Canadian government to be directly involved in exports through one of its Crown corporations. There were, however, public criticisms of the government's move; mainly that the reactor game was too difficult and that Canada was overreaching itself.

A small sales team was assembled by AECL, initially supported by the proposals group from CGE. Eventually, the proposal preparation, along with the overall technical responsibility for reactor projects, was transferred to the Power Projects Division of AECL, now the AEC Engineering Company. The sales team was small but well supported by the technical staff, and strengthened by the active participation in marketing of AECL's President, and of its Vice-President for Power Projects.

From 1968 to 1972 proposals were prepared for Romania, Mexico, and Australia as well as an effort in Greece late in the bidding process. None of these resulted in the award of a reactor project to AECL or to its competitors. Only Mexico eventually awarded a project to an American company in a second round of tendering in which AECL did not participate. In Romania, negotiations for a 600 MWe CANDU were close to their conclusion when disastrous floods in that country prevented Romania from raising the necessary funds. Discussions were not resumed until 1975.

Because of the costly investments in manpower and money made by AECL in these markets (each bid cost about $1 million), the lack of a favourable result was disappointing. However, valuable experience was gained in developing the detailed commercial and technical aspects of preparations and in understanding export financing and the nature of the market. Also, as a result of a detailed evaluation of bids undertaken in Mexico, confidence was developed in the competitive position of the CANDU relative to other systems and in the technical depth supporting the CANDU. However, marketing in the period before Pickering established its performance record was still hampered by the lack of demonstrated system performance.

Taiwan

An NRX-type research reactor was sold to Taiwan in 1969. Shortly afterwards, Canada recognized mainland China and severed diplomatic relations with Taiwan. Since then Canada has not responded to possible Taiwanese interest in a CANDU.

Denmark and Australia

Despite considerable effort by AECL in Denmark with a sympathetic utility, and also in Australia, both countries decided to postpone their commitment to nuclear power.

Argentina - Embalse

In early 1972, the decision was taken to participate with an Italian company, Italimpianti, in the bidding for the 600 MWe Embalse (Cordoba) project, Argentina's second power reactor. It was agreed that AECL would assume the cost and commercial risk responsibilities for the marketing and supply of the nuclear part of the station, and Italimpianti would do the same for the electrical generating part. In March 1973, after detailed evaluation of bids, Argentina chose the AECL/Italimpianti turnkey offer for contract negotiation. The contract was signed in December 1973, and became effective in April 1974, two years after the initial decision to make a bid.

The delay is typical of the time required for preparing, bidding, and negotiating reactor export contracts. It was not Canada's first venture into the Argentine market, and a number of subsequent negotiations have occurred with respect to the same project. Reactor sales require patience to obtain. Once consummated they represent very long-term commitments by the partners.

Italy

AECL chose to work with an Italian company in Argentina, partly because of that company's knowledge of the Argentine market but also because of AECL's interest in obtaining a project in Italy. It was thought that a good result in Argentina would encourage Italy's state electrical authority (ENEL) to look favourably on a CANDU offer. A substantial effort was made by AECL in the early 1970s to tender to the extensive specifications and terms of ENEL's invitation to bid on a program of four reactor units. AECL was bidding against Italian licensees of U.S. vendors. It could not accept, as these Italian companies could, the commercial risk associated with ENEL's terms. AECL bid accordingly and did not obtain any of the four units awarded in 1975. Because of siting and other problems, none of these awards has yet been translated into a firm supply contract.

As a result of its bidding experience in Italy, AECL decided to seek an Italian licensee for the CANDU system. In December 1976, an agreement was entered into with PMN, an Italian company in a group controlled by the state. The three year term of the agreement has now expired without result, but the parties have extended it. Italy's program of eight reactor units beyond the four already awarded (but not yet begun) is stalled because of a variety of problems.

Korea

In 1973, AECL concluded an agreement with United Development Incorporated (UDI) to represent it in the Republic of Korea, a market with which UDI was familiar. At that time the Korea Electric Company (KECO) had its first nuclear power plant, a 600 MWe LWR from the U.S. under construction. Negotiations were pursued intensively during 1974, and in early 1975 the commercial contract was signed. Because of delays introduced by subsequent negotiations on financing and safeguards, the supply contract did not become effective until 1976.

The Korean CANDU contract, with its ample scope of supply, has developed so far to the satisfaction of AECL, the nuclear industry, and the governments of Canada and Korea. As in the Argentinian sale, however, there have been political problems in Canada about the accountability of the agents for the fees they received. Business associates or partners will clearly be necessary for AECL in many of their offshore markets, but its dealings with them will also have to meet the test of public scrutiny back home. Korea is now looking for larger units, in the 1000 MWe range, but may consider a second 600 MWe unit at Wolsung.

United Kingdom

In 1975, the UK's commercial reactor program based on the AGR was not going well. Strong support developed within the Central Electricity Generating Board (CEGB) and the U.K.'s

General Electric Company (GEC) for the introduction of the U.S.-developed PWR system. At that time, the U.K. also had in operation a 92 MWe prototype Steam Generating Heavy Water Reactor (SGHWR), which had functioned reasonably well since its completion in 1968.

At this point, AECL attempted to interest the U.K. in the CANDU system. The winning of a contract for the CANDU in a major industrial country, even in a licensing arrangement, would have meant a great deal for the CANDU's reputation at this point. However, AECL soon recognized the weight of resistance in the CEGB and the GEC, and the generally prevalent conceptual difficulty at the idea of importing large-scale technology from Canada. With the support of Ministers from the governments of Ontario and Canada, AECL promoted Canadian co-operation with the U.K. in the commercial development of the SGHWR, which was similar to Gentilly I. This strategy worked. The introduction of the PWR was delayed, and the U.K. undertook to design a SGHWR scaled up to commercial size. After about two years of problems in scaling up the SGHWR and with internal organizational difficulties in the British nuclear program, the SGHWR project lost much of its momentum.

The U.K., which had not ordered any new reactors for 11 years, recently committed itself to two more AGR's. Although there is still some support for the CANDU, the U.K. is believed to be planning a series of LWR s for its next round of reactor orders.

Romania

The Romanians approached AECL in 1975 to express interest in a 600 MWe CANDU station. Whereas negotiations in the 1960s had focused on turnkey supply, the Romanians now wanted to reserve the project management function for themselves and obtain a licensing agreement together with services from AECL. Three agreements were signed in December 1978: Licensing, Engineering Services, and Procurement. The latter two are being renegotiated as of the fall of 1980 to extend their application to a second CANDU unit. Romania has plans to expand its CANDU program to include 16 units, most of which it would like to build itself.

Japan

Japan has a rather ambitious nuclear program with 15 GWe of nuclear capacity on line now and up to 30 - 40 GWe in each of the next two decades.

Serious interest in the possibility of introducing CANDU into Japan was first expressed in 1976, but since then its future has been problematic. The interested agency is the Electric Power Development Company (EPDC). Japan's nine major regional utilities are each strongly associated with one of three Japanese suppliers. The suppliers in turn license their nuclear systems from either Westinghouse or General Electric. The EPDC and several other development-oriented companies serve as vehicles for investigating new generating technology.

After a brief exploratory review indicated that the CANDU should be acceptable under Japan's seismic regime without major modifications, EPDC signed a $1.7 million contract with AECL for a more detailed study, completed in December 1978. In parallel with this study the parties examined project supply arrangements and EPDC engaged in seeking a site.

In August 1979, hopes for the CANDU were set back by an announcement by the Japanese Atomic Energy Commission (JAEC) that it would support its own advanced thermal reactor (ATR) rather than the CANDU, even though the ATR, a heavy water moderated, light water cooled system, is still in the experimental stage. The JAEC stated that it could not find sufficiently strong positive reasons to recommend the introduction of the CANDU (as an intermediate system between the LWR and the fast breeder) to Japan at this time. However, the door is not completely shut to the CANDU. It was the subject of discussions between Prime Ministers Trudeau and Ohira in 1980, and EPDC has also signed another study contract with AECL.

Argentina - Atucha 2

In 1978/79 AECL made a major marketing effort to obtain the award of Argentina's third nuclear power plant, Atucha 2. The prize also included a favourable position for obtaining participation in a program involving three more 600 MWe reactor units. Tenders were to include proposals for technical and industrial co-operation on the four-unit program. The major competitor was the German firm, Kraftwerk Union (KWU). Siemens, which now owns KWU, had

built the 350 MWe Atucha 1 heavy water reactor and KWU planned to scale up the pressure vessel to over 600 MWe for Atucha 2, a challenging task. Thus the Germans were again marketing a reactor abroad which they had not yet built at home.

The Embalse CANDU had run into serious problems. Delays and cost concerns, due in part to the severe inflation which followed the 1973 oil crisis, threatened to saddle AECL with huge debts. Negotiations in 1977 limited AECL's loss to $130 million. Citing problems with the Embalse CANDU, Argentina in 1979 awarded the third reactor to KWU. At the same time it contracted with a Swiss firm, Sulzer, for a heavy water plant which AECL had also offered.

The negotiations with Argentina over the Embalse and Atucha 2 reactors were complicated by the evolution of Canadian safeguards policy. After the Indian nuclear explosion of May 1974, and Canada's new nuclear export policy requirements of December 1974, Canada requested bilateral negotiations with Argentina to bring the agreement on the Embalse reactor up to the standards of Canada's new policy. These conditions were satisfied in 1975.

In December 1976, Canada announced that acceptance of full-scope safeguards by the purchasing country would be a requirement for all future nuclear export contracts. This was not applied retroactively to the Embalse or other existing contracts. However, the Embalse agreement was limited to completing the reactor and assuring its safe and efficient operation. Any further cooperation, such as the Atucha 2 reactor, would require full-scope safeguards. While Argentina did not mention safeguards as a factor in awarding the Atucha 2 reactor and the heavy water plant to KWU and Sulzer, they may have played a role. The conditions required by the Germans and Swiss are less stringent and did not require full-scope safeguards.

There is still a possibility that AECL could be chosen as the supplier of one or more of the remaining three heavy water reactors that Argentina plans to build in this century. Although all of Argentina's significant nuclear facilities are believed to be under safeguards at present, there is no indication that Argentina is prepared to accept the principle of full-scope safeguards, as required by present Canadian policy.

OBSERVATIONS ON CANDU EXPORTS

A. The Market

Hopes and plans for CANDU exports must be based on a realistic view of the market. Exaggerated expectations in the early 1970s may have led to undue criticism in Canada later on of our export efforts. Assessment of the actual details of AECL's marketing efforts on the different projects and the government's actions in support of them is beyond the scope of this outline, but it is not obvious that greater marketing skill or political commitment would have made much difference.

At a time when reactor sales by any country are few, individual sales take on elements of great drama. Each sale is indeed critical, and the award of a reactor contract can be an important factor in sustaining activity and enthusiasm in the domestic industry. Nonetheless, it must be recognized that the export market for reactors will develop relatively slowly and erratically, and that commitment to exports must be seen in the context of the longer term.

The reactor market is by no means homogeneous. It consists of a variety of countries with different needs. The larger industrial countries are all virtually committed to the LWR and beyond that, to the fast breeder. It is hoped that some of them will find a niche for the CANDU, which provides a better symbiotic partner for the breeder than the LWR. If such a country (Italy, Japan, Britain) were to license the CANDU design, it would add considerably to the prestige and influence of the CANDU in world markets.

Smaller industrial countries such as Australia, New Zealand, and those around the fringes of Europe (Denmark, Netherlands, Ireland, Portugal, Greece, Yugoslavia, Romania) are also desirable potential markets. Some of them have already embarked on nuclear power programs (Netherlands, Yugoslavia, Romania) but in general they have been slow to commit themselves. The more industrialized countries are attractive customers from many points of view, but it will not be easy for CANDU to penetrate these markets.

Among the developing countries, the oil-exporters are in the best position to afford the capital investment in nuclear power. However the human and technical infrastructure required to assimilate nuclear power is not always as well established as in the advanced industrializing countries, and the political foundation for nuclear power may be less secure because the immediate need for it is less obvious.

There are a number of newly industrializing developing countries such as Taiwan and South Korea which can use nuclear power to offset their dependence on imported oil to fuel their rapid industrialization. In other cases, some countries which most need nuclear power to replace oil can least afford it in the short term. Still others like Argentina, Mexico, or Brazil have a variety of energy resources but apparently see nuclear power as a legitimate and competitive component in their energy supply pattern.

Mexico recently commissioned studies by three countries in order to decide which vendor and reactor type it will select for its future program. France studied the PWR, Sweden the BWR, and Canada the CANDU. Mexico has reviewed the studies and is expected to place its first orders in 1981.

Some of the poor, populous, predominantly agricultural countries such as India and China have an industrial sector which, although small in terms of their overall economy, is large enough in absolute size to accommodate a nuclear program. Indonesia, despite other energy supply possibilities, has expressed interest in a future nuclear power program.

Each marketing opportunity is unique, and the approach must be tailored to the situation, from a design licence for advanced industrial countries to a turnkey plant for the less developed. The customer may be an importing agency (Romania), an atomic energy commission (Argentina) or a utility (Korea), whose primary interests and criteria for decision will be oriented according to their mission.

For AECL, there are about 40 countries which might be considered, in varying degrees, as potential markets for nuclear power reactors. Their published intentions are for the addition of about 100 units before 1990, beyond the 123 units already in service or on order in those countries.

A recent study (7) for the International Consultative Group on Nuclear Energy suggests that the export market for nuclear reactors in the 1980s will be of the order of 4-6 units per year. Given the present uncertainties, a wide range of market estimates must be considered.

Reactors smaller than about 600 MWe are considered uneconomic by most Western vendors. Since utilities prefer to have no more than about 10 per cent of their capacity in any one unit, for the sake of system reliability, a grid size of about 6 000 MWe is required in order to accommodate a nuclear reactor when it comes on line. The number of countries which can consider accepting such reactors is limited.

The Soviet Union sells 440 MWe units. India is continuing with a series of 200 MWe CANDU-type units, but has not yet attempted to export them. There are periodic reports of smaller reactors available from Western vendors. No prototypes yet exist of such reactors, and it is difficult to see how they could compete under today's market conditions, although rising costs of alternative sources could make smaller reactors competitive at some point. The availability of competitive nuclear reactors of 200 MWe would broaden the reactor market considerably.

For both the vendor and the purchaser, nuclear reactor sales are very important and visible projects. The long lead times needed to cultivate the market, prepare bids, negotiate contracts, obtain regulatory approval, and build and commission plants require long-term economic and political commitments to nuclear co-operation. Even after they are in service, the reactors will involve the two countries in a continuing relationship to ensure safe and efficient operation. Perceptions of the strength and stability of the vendor government's commitment to the project are essential components of the decision to purchase a nuclear reactor.

Exports must be cultivated well in advance. Vendors may find that they are negotiating with people who have been in the game for 10 or 20 years or who may have studied or trained in

one of the vendor countries many years earlier. Also they may be helped by marketing staff who have an intimate knowledge of the purchasing country and its customs from earlier contacts.

AECL must be selective in determining which countries merit a major marketing effort, and in concentrating efforts on the key elements in that country. This requires excellent market information on the industrial and energy strategy of the country, its political and economic policies, the important institutions, the key decision-makers, and the criteria which will most influence its decisions.

There will be a continuing need for local agents or partners in most countries. These may be local companies, or foreign companies with extensive experience in the relevant areas. Ideally, they would be able to collaborate with AECL and Canadian industry both on marketing and on complementary engineering services for the balance of the plant.

B. Marketing

For this essential activity AECL, the appropriate agencies and departments of the federal government, the nuclear manufacturing industry, and the provincial utilities with nuclear programs (especially Ontario Hydro) all have a role to play. The major challenge facing both AECL as lead actor, and the federal government as setter of policy, is the co-ordination of these roles to obtain the best contribution from each participant and to assemble them in a coherent program.

In some potential customers, Canada may present a decentralized operation. Approvals may be required by Cabinet or by committees within the bureaucracy. AECL is responsible for marketing but has its own particular interests to advance. Ontario Hydro has the kind of project management and operational expertise that interests customers but it has no mandate for exports. The manufacturing technology is owned by a number of industrial firms. AECL requires a clear mandate and broad support if it is to provide the necessary leadership.

Ontario Hydro has already participated significantly in the marketing of CANDU reactors. Training programs offered in conjunction with the sale of CANDUs have included the use of Ontario Hydro's training staff, facilities, and reactors. In addition, it has been co-operative in accepting and hosting numerous visits to its reactor sites and participating in marketing visits. The Ontario Government too has been vocal in the promotion of CANDU, particularly in Europe and Japan.

At the same time, Ontario Hydro's present mandate would not permit it to accept substantial project risks outside of Ontario. Consequently, services provided to foreign CANDU projects are now made on a service cost basis with the primary contractor, AECL.

The participation of Hydro-Québec and New Brunswick Power is also valuable because of their experience with the 600 MWe CANDU units which are similar to the standard export reactor.

C. Licensing and Industry

During the negotiating of the AECL/PMN licensing agreement for Italy, members of the Canadian nuclear industry expressed concern that an Italian competitor might be created without the industry obtaining any direct benefit. This raised the question of Canada's marketing strategy and the role of AECL as the lead actor. From AECL's point of view licensing was a necessary way of extending the CANDU share of the reactor market since potential customers were reluctant to commit themselves to a single, relatively small supplier. In AECL's view, licensing another industrial country would make an alternative supplier available. Gains made through additional customers would offset any contracts lost to the other CANDU suppliers, since the main competition was the LWR. In any event, AECL was confident it could stay ahead of the competition technically on the nuclear steam supply system and on heavy water supply. Industry saw the situation differently. It faced direct competition from the lower-cost country, the licensee, for a limited heavy water reactor market. The industry felt that in its negotiations AECL might be tempted to look after its own interest at the expense of the industry's.

In response to the industry's concern, a specific level of equipment purchases from Canada was set out in the Italian agreement as a prerequisite for PMN to obtain CANDU export rights. From this experience Canadian industry recognized the value of acting collectively. Eight companies formed Canadian Nuclear Equipment Suppliers (CNES).

There is evidence that AECL and the industry have begun to work together more harmoniously. An industry task force recommended in 1978 that AECL continue to take the lead role in marketing. Most of the nuclear manufacturers have other activities beside their nuclear ones, and do not have the resources to take such a lead role nor can they assume the major risks involved.

In 1979, CNES was dissolved and replaced by a larger industrial group of about 40 companies, the Organization of Candu Industries (OCI). It has worked closely with AECL in recent marketing efforts in Mexico, China, and Yugoslavia. It has also taken some intitiatives of its own, and is heavily involved in negotiations with Romania on technology transfer. In general, the equipment suppliers have insisted on sales to a given country of at least two units, with substantial Canadian manufactured content in each one, before licences for manufacturing technology are granted.

A Joint Export Marketing Committee has been established to assist AECL, with participation by industry through the OCI, by the three utilities with nuclear programs, and by ITC. This ensures that AECL is aware of industry and utility viewpoints in its marketing activities.

D. Competition

The most striking feature of the companies with which AECL competes for reactor exports is their size. General Electric, Westinghouse, and Siemens (KWU) are large diversified multi-national companies with considerable experience in the supply of electrical generating equipment from the pre-nuclear era. Framatome, the other main international competitor, has sole access to the French domestic nuclear program of about 40 reactor units, which is the most dynamic major national program in the Western world. These firms integrate experience in reactor design, conventional engineering and manufacture, fuel fabrication, and project management skills. Their financial and human resources are substantial. They may have enjoyed stronger apparent support from their governments than has been the case with AECL. Their governments may in turn be in a better position to bring to bear a broader range of economic and political considerations to reactor sales, such as resource and technology exchanges, financial and technical assistance, security agreements, etc.

Because of the decrease in planned nuclear generating capacity around the world from the higher expectations of the early 1970s, nuclear industries in all the supplier countries except France and the U.S.S.R. suffer from severe overcapacity. All the suppliers are looking to a shrinking export market to provide the orders they need to tide their nuclear industries over the lean years ahead. The competition in the early 1980s will be intense.

It should be observed that the competition has also had its share of problems. LWR projects in Brazil, Mexico, Yugoslavia, and the Philippines have been subject to delays of various kinds. In Iran there was a complete cancellation of the French and German reactor projects for political reasons.

Nonetheless, as noted previously, the LWR already enjoys a considerable lead in the world reactor market. The strength of the competition is a measure of the effort and commitment that will be required to market the CANDU.

E. Performance Record

The CANDU has had to establish an excellent performance record in order to overcome the doubts of potential customers. The strength of AECL as an institution has been perceived to be its R&D capability rather than engineering or project management. The success of the Ontario Hydro CANDU reactors at Pickering and later at Bruce has helped greatly in this respect. Customers now know that the CANDU has performed very well in Ontario, with high reliabilty, very low fuelling costs, and competitive overall energy costs, proving that performance is not limited by the design.

Ontario Hydro is a large, well-financed, and well-managed utility and it has worked closely with AECL since the inception of the nuclear program in Canada. Some potential customers may also have concerns about the problems involved in building and managing a CANDU system to the same high standard in their own countries. Despite the current excess capacity in Canada's reactor manufacturing and heavy water industries, they may also be concerned about Canada's ability to support CANDU programs in other countries.

Good commissioning and performance of the 600 MWe CANDUs now approaching completion in Quebec, New Brunswick, Argentina, and Korea will be a key factor in establishing the CANDU 600's reputation and marketability over the next 10 years. In particular, successful commissioning and initial operation of the Embalse reactor will do much to counter the effect of earlier Argentine criticism of AECL's performance there.

Results from the intial performance of these reactors will not be available until 1983 or 1984. This is too late to have any influence on the hiatus in orders over the next few critical years, but it will be crucial for orders from the mid-1980s onwards. Clearly, anything that can be done to ensure the safe and efficient commissioning and initial operation of the 600 MWe CANDUs will be essential to the success of Canada's long-term reactor marketing efforts.

Other countries with established reputations as suppliers of large-scale high-technology projects have not had to work as hard to gain confidence. As noted, the LWR swept the market before its costs and performance record were clearly established. Argentina has twice ordered reactors from Germany which had not been proven at home.

In this respect, the minority position of the CANDU in the world market takes on added importance. Anything that can be done to diminish the perception that CANDU purchasers depend on a single supplier, or to strengthen the technical base supporting the CANDU, would be useful in this regard. Licensing agreements now seem to have the support of the nuclear industry. Nuclear engineering courses, programs, workshops and training arrangements, perhaps in conjunction with university engineering departments, could ensure greater familiarity with the CANDU system among nuclear engineers, scientists, regulators, and planners in other countries. (In this respect it is interesting that there are, as yet, no nuclear engineering or science textbooks on heavy water reactor systems).

Regulatory assistance on safety and performance standards by the Atomic Energy Control Board (AECB) is particularly important, given the broad support that exists for LWR standards throughout the world.

It might also be worthwhile to consider the establishment of an international heavy water reactor association, perhaps under the leadership of users other than Canada. Advantage could be taken of the continuing interest in heavy-water-moderated, light-water cooled reactors in Italy, Japan, and elsewhere, and also of interest in thorium-fuelled systems, to broaden the base.

If Canada is to continue as a unique supplier, at least for the time being, it must be perceived as reliable. It is unfortunate from this point of view that of the six countries to whom Canada has sold reactors (including research reactors), nuclear co-operation has been terminated with three of them (India, Pakistan, and Taiwan), for political rather than technical or economic reasons in each case. Since long-term commitment and co-operation are essential to ensure performance in reactor projects, it is vital that any further policy moves by Canada be carefully weighed for their impact on world perceptions of Canada's reliability.

F. Cost, Scale, and Standardization

The CANDU has undeservedly earned the reputation of being a higher capital-cost reactor system than the LWR. This may in part be explained by early cost comparisons between the first commerical reactor units committed in the U.S. and Canada. Whereas the estimated capital cost of such plants as Oyster Creek was reportedly $125 to $150/KWe, that of Pickering A was $375/KWe. However, units committed early in the U.S. program were sold at huge losses and published figures did not include all customer costs. More recent cost comparisons have indicated that CANDUs can be constructed within 10 per cent of the cost of LWRs depending upon

the regulatory system. The added cost of CANDU's heavy water inventory is partly offset by LWR s higher fuel inventory cost.

Cost comparisons are complicated by the lack of good base data. For example, large and, to some extent, unexplained cost differences have been reported by U.S. utilities installing apparently identical reactor systems. Different financing charges, site characteristics, construction schedule differences, regulatory requirements, labour costs, and efficiency experiences contribute to the difficulty in identifying the base cost of a reactor plant.

In assessing nuclear power costs, one must of course look not just at capital cost but at total unit energy costs. Through its very low fuelling cost and high availability factors in operation, the CANDU can offset reasonable capital-cost disadvantages in producing cheap and relatively inflation-proof electricity.

The specific capital cost of a 4 x 600 MWe station will be about 25 per cent cheaper per MWe than a single 600 MWe station. A single 900 MWe unit will be about 10 per cent cheaper per MWe than a single 600 MWe unit. These considerable savings suggest that for those nuclear programs which can accommodate large increments in generating capacity, larger units and multi-unit stations will be preferred. This emphasizes the importance of individual sales and of having large units available. It also increases the strain on export financing.

Standardization is an elusive goal. Unavailability of standardized, detailed reactor design was a major cause of difficulty with the Argentina Embalse CANDU project. The 600 MWe units now offered by Canada are in principle standard but a number of factors have prevented the extensive standardization of plant. These include the Canadian practice of seeking competitive bids on components, evolving regulatory requirements, specific requirements of particular utility customers, and site considerations.

G. Assets and Obstacles to CANDU Exports

The advantages of the CANDU system were outlined in a recent presentation by a senior AECL marketing official:

1. lower lifecycle generating costs;
2. higher utilization of uranium - conservation of resources;
3. the ability to use natural uranium-greater independence of fuel supply;
4. high plant availability of CANDU stations;
5. design features which enhance inherent safety;
6. ease of manufacture - ease of maintenance;
7. ease of handling and storing fuel - fresh or irradiated;
8. secure supply of heavy water from Canada;
9. obsolescence-resistant fuel cycle options that can be introduced in the future without major change of reactor design and manufacturing concepts;
10. Canadian experience of industrial applications of nuclear heat.

It seems unlikely that nuclear heat applications will be a major selling factor in the near term. Also, most countries would prefer to have their own heavy water supply rather than depend on another country. However, national heavy water programs have proven rather difficult to match to the pace of reactor commissioning, but now that Canada has established a surplus heavy water production capability, customers may be willing to obtain heavy water from Canada, with perhaps a small plant of their own for make-up or emergencies.

The other points underline the strong technical and economic arguments in favour of the CANDU, the excellent performance record it has established, and the future options open to it through evolution into thorium fuel cycles. These are necessary conditions for sales but are not in themselves sufficient.

In broader terms, it appears that the most attractive aspect of the CANDU system to potential customers is the degree of autonomy it offers to medium-sized nuclear programs in industrializing countries and the relative ease with which much of the associated technology can be transferred. This seems to have been the principal criterion in India, Argentina, and Romania. Pakistan may have simply seized on a good opportunity to make its debut in nuclear

power, and to keep pace with India, although here again the prospects for autonomy may have been appealing.

In the case of Korea, diversification seems to have been the main asset of the CANDU. That country would like to have some fraction of its capacity derived from heavy water reactors. In some countries where LWR programs have had a difficult start, such as Yugoslavia and Mexico, the CANDU may derive its appeal both from diversification to offset the risk of failure, and from the greater degree of autonomy it offers.

The desire to deal politically with Canada as a country may also favour the CANDU, compensating somewhat for its isolated situation in the market. Customers which already have intensive economic and political arrangements with the United States or one of the other major industrial suppliers may wish to reduce their degree of dependence on those countries. Canada is less likely to use nuclear agreements as leverage on broader policy issues. Conversely, the nuclear agreements may be relatively more important to Canada, thus providing greater leverage for the customer. However, this aspect must be weighed by customers against Canada's past willingness to make major unilateral policy changes even at commercial cost to itself.

The apparent decentralization of the Canadian marketing effort among government, AECL, the nuclear industry, and the utilities may have one offsetting advantage. Some industrializing countries are looking for ways of "unbundling" the package deals offered to them by industrial countries on large-scale high-technology projects. They want to look at smaller parts of the project with an eye to seeing what parts they could obtain on a competitive basis elsewhere, what technologies they could rapidly assimilate in their own smaller-scale industries, etc. It may be easier for them to do this with the CANDU than with some of the more integrated suppliers. This simply emphasizes that Canada must be flexible in co-ordinating its own marketing activities and tailoring them to the needs of individual customers.

There is continuing controversy about the importance of financing in obtaining reactor sales. In today's buyer's market, some developing countries attempt to use a component of concessional financing as a tool to play the suppliers off against each other.

Future sales may require multi-unit stations composed of large individual units. For a 4 x 850 MWe Darlington-type station, Ontario Hydro estimates the cost at 1980 $5.5 billion - $2 billion for the nuclear part of the plant, $1 billion for the electrical generation, and $2.5 billion for the civil works. Even the $2 billion for the nuclear part represents a considerable exposure for Canadian export financing in a single country.

Because of the comparatively recent phenomenon of high interest rates in North America, European financing terms appear, at least superficially, more attractive to potential customers. Such rates may represent lower expectations of inflation and are not directly comparable. In fact, the higher apparent interest rate may in the long run be cheaper. Nonetheless, purchasers feel more comfortable with quoted low interest rates as these appear to offer less risk, especially in the near term. Apart from forceful argument to customers about the real cost of money, this problem may require some special financing arrangements. More generally, as competition intensifies for a few large orders in a small market, financing may become a more critical factor in exports. Imaginative ways of sharing the risk between the government and the private sector will be increasingly necessary.

H. Political Considerations

Canadian safeguards policy is considered in some quarters to be a serious impediment to Canada's ability to export CANDU reactors. Our demands for full-scope safeguards, for binding commitments to non-proliferation independently of NPT membership or of international safeguards, and our insistence on an effective veto over reprocessing of the plutonium produced in CANDUs, are seen as going well beyond the conditions requested by other suppliers.

Full-scope safeguards are a requirement for parties to the Non-Proliferation Treaty (NPT), so they represent a problem only for a limited number of non-signatory countries. However, several of these are potential customers for reactors, although not necessarily CANDUs: Argentina, Brazil, Columbia, Cuba, Algeria, Spain, Saudi Arabia, Turkey, Egypt, Israel, South Africa, India, Pakistan, and China. So far, these countries have been able to import

reactors, if they choose, with safeguards applied only to the imported facilities and not to their entire national nuclear programs.

It is not clear for how many of them a decision not to buy the CANDU would be based primarily on Canada's request for full-scope safeguards. It is unlikely, however, that many would accept full-scope safeguards simply to obtain a CANDU.

For countries which are members of the NPT, safeguards should not be a problem. Nonetheless, some countries with impeccable non-proliferation credentials are reluctant to enter into bilateral agreements with Canada which go beyond the requirements of the NPT. Canada does not have objections in principle to reprocessing in countries where there is a good economic and technical case for it and where Canada's non-proliferation concerns are satisfied, and should be able to reach agreement with such countries as to what the conditions should be for Canada's prior consent for reprocessing to be given on a reliable and predictable basis. Again, there is reluctance on the part of some customers to grant Canada such consent rights.

Apart from specific safeguards requirements, Canada makes political and ecomomic assessments of potential reactor customers and discourages sales to countries which may be subject to domestic or external instabilities or security threats. These assessments must be brought up to date from time to time. However, judgements are inevitably made in terms of the present situation and there is some question as to how such judgements can take into account the developments which will occur over the ten years required to build a reactor and over its operating life.

Taiwan is a particular case since Canada does not have diplomatic relations with that country.

CONCLUSION

A brief sketch of the development of Canada's nuclear reactor exports has been presented and some of the factors which influence our ability to export reactors have been identified. The potential market for CANDUs is small and will develop slowly. The competition will be tough. There are few good prospects for immediate export orders in the next two or three years. Nonetheless there are reasonable opportunities for CANDU exports, especially in the mid-to-late 1980's. Such sales could be of great benefit to Canada and could do much to sustain the domestic nuclear industry.

Apart from its excellent economic and technical performance, the main attraction of the CANDU seems to be the autonomy it confers on purchasing countries, the effectiveness with which the associated technology can be transferred, and the diversification it offers to countries which wish to reduce their dependence on the major industrial suppliers. Each sales opportunity is unique, and marketing strategy will have to be tailored to the customer's needs.

Over the next decade, the factors susceptible to Canadian government action which are most likely to influence CANDU exports will be the political commitment of the government to those reactor exports, the performance established by the four 600 MWe CANDUs now nearing completion, the continuing successful operation of the nuclear program in Ontario, and the co-ordination of the different components of Canada's nuclear program (AECL, nuclear industry, utilities, and government) in putting forth a coherent marketing effort and following through with effective project management.

Casterton, J. International Dimensions of the Canadian Nuclear Industry. M.A. Thesis. Ottawa, Carleton University, 1980.

Doern, G.B. Government Intervention in the Canadian Nuclear Industry. Montreal, Institute for Research on Public Policy, 1980

Doern, G.B., and R.W. Morrison, eds. Canadian Nuclear Policies. Montreal, Institute for Research on Public Policy 1980.

Langstaff, J.H. Marketing CANDU Internationally. Address to the 20th Annual International Conference of the Canadian Nuclear Association. Montreal, June, 1980.

Law, C., and R. Glen. Critical Choice: Nuclear Power in Canada, the Issues Behind the Headlines. Toronto, Corpus Information Services, 1978.

Leonard and Partners. Economic Impact of the Nuclear Industry in Canada. Report to the Canadian Nuclear Association. Toronto, 1978.

Lonnroth, M., and W. Walker. The Viability of the Civil Nuclear Industry. New York, International Consultative Group on Nuclear Energy and London, Royal Institute of International Affairs 1979

Morrison, R.W., and E.F. Wonder. Canada's Nuclear Export Policies. Ottawa, Carleton University, June, 1979.

Royal Commission on Electric Power Planning. Chairman: Arthur Porter. A Race Against Time: Interim Report on Nuclear Power in Ontario. Toronto, 1978

Royal Commission on Electric Power Planning. Chairman: Arthur Porter. Final Report. Volume I: Concepts, Conclusions and Recommendations. Toronto, 1980.

Sabato, J.A. "Atomic Energy in Argentina: A Case History" World Development, 1: August, 1973.

Sims, G. The Evolution of AECL. M.A. Thesis. Ottawa, Carleton University, 1979.

Task Force on CANDU Export Marketing. Chairman: J.M. Douglas. Report. Ottawa, Department of Industry, Trade and Commerce, 1978.

THE STRUCTURE OF CANADA'S URANIUM INDUSTRY AND ITS FUTURE MARKET PROSPECTS

This paper was prepared by the
Uranium and Nuclear Energy Branch, Energy Sector
Energy, Mines and Resources Canada
November, 1980

CONTENTS

INTRODUCTION

Canada's uranium industry began in 1930 with the discovery of the Port Radium pitchblende deposit in the Northwest Territories. From 1933 to 1940 the deposit was exploited primarily for its radium content. The mine was closed in 1940 and reopened in 1942 to recover uranium for nuclear weapons development work in the United States. Soon after the federal government expropriated it and prohibited private sector uranium exploration. Although this ban was removed in 1947 Eldorado Mining and Refining Limited, a Crown company, remained the sole buyer of privately produced uranium until 1958.

Exploration in Canada expanded in response to what seemed like unlimited uranium requirements for American and British defence purposes. The discoveries which followed led to a production industry that peaked in 1959 with 23 mines and 19 ore processing plants in 5 districts. In that year, concentrates were shipped containing 12 226 tonnes of uranium valued at over $331 million. Uranium ranked fourth in value among Canada's exports, after newsprint, wheat, and lumber.

After 1956 no new defence contracts were signed and the industry suffered a sudden loss of markets. The United States declined to take up any of its options for the purchase of additional uranium. Uranium production declined rapidly although the United Kingdom was persuaded to take up an option under its contract. The federal government took steps to cushion the industry from the abrupt fall in demand. By 1965 production fell below 3 000 tonnes of uranium per year, and only 5 production facilities remained in operation, two of which had ceased mining and were recovering uranium solely from the treatment of mine waters. Virtually no uranium exploration took place in Canada during the 10-year period 1956 to 1965.

In 1966, uranium exploration resumed in response to a growing demand for nuclear electricity generation. The orderly development of the market was hampered during the late 1960s however, partly because of delays and difficulties in nuclear power development programs and partly because of an over-supply situation related to the existence of producer inventories and government stockpiles built up in earlier years. Existing uranium producing facilities operated at levels below capacity.

By 1971 the international uranium market was in a chaotic state and prices had declined to a level lower than the operating costs of many producers. Uranium policies originating in the United States served to exacerbate the difficulties encountered by non-U.S. producers. Following unsuccessful efforts to ameliorate the situation by discussion with governments of several consuming countries, the Canadian government authorized Canadian producers to enter into an informal marketing arrangement with non-U.S. producers. This arrangement provided for an equitable distribution of the export market (excluding the U.S. market and the domestic markets of France, South Africa, Australia, and Canada) and the establishment of a reasonable level of minimum prices.

By 1974 producer inventories and excess capacity had become fully committed, and prices had recovered to levels well above the minimum price levels established under the international marketing arrangement. Consequently, the "arrangement" was dissolved and all restrictions relating to quotas and prices that had been imposed on Canadian uranium exports during the period of the "arrangement" were removed. Prices continued to rise as consumers moved to contract for their longer term needs. Increased generation of nuclear power was planned in the wake of the 1973 international oil crisis and there were expectations that the operating tails assays of the United States' enrichment plants would be increased, thus requiring larger quantities of uranium feed. In late 1975 Westinghouse Electric Corporation revealed that it would not be able to deliver over 25 000 tonnes of uranium to its various utility customers in the U.S. and abroad. Consequently, prices reached $US 104/kg U ($US 40/lb U_3O_8) by early 1976, but generally stabilized thereafter. Mainly in response to these price increases exploration gained considerable momentum and by 1978 had reached a very high level.

Since the mid-1970's there have been successive downward adjustments in projections of nuclear power growth. Moreover, potential uranium supply capability increased as a result of new uranium discoveries in many parts of the world. These developments have resulted in a growing imbalance between uranium requirements and potential uranium supply, which is expected to last throughout the 1980's.

1. STRUCTURE OF THE INDUSTRY:

The current structure of the industry is described according to four separate phases: exploration, production, marketing, and refining. Much of the data used for this analysis is taken from Energy, Mines and Resources' (EMR's) 1978 Assessment of Canada's Uranium Supply and Demand. The 1979 Assessment, to be published late in 1980, would not appreciably alter the description of the industry.

a) Exploration Phase

The most recent surge in uranium exploration began in 1973, mainly in response to increasing prices as consumers moved to secure long-term supplies. Canadian exploration expanded throughout 1974 and 1975. By 1976, total expenditures had reached about $43 million,

Table 1
Uranium Exploration Activity in Canada by Province or Territory, 1977 and 1978

Province or Territory(1)	Exploration Expenditures(2) (millions of dollars)		Exploration and Surface Development Drilling(3) (thousands of metres)	
	1977	1978	1977	1978
Saskatchewan	35.3	43.6	192.4	233.4
Northwest Territories	13.8	17.0	14.3	18.9
Quebec	8.4	7.4	35.9	21.2
British Columbia	2.2	7.0	18.1	25.4
Newfoundland	2.3	2.8	6.1	6.8
Nova Scotia	1.5	2.4	1.9	9.7
Ontario	2.6	2.3	24.7	11.0
New Brunswick	1.0	1.2	4.1	2.8
Alberta	1.0	1.1	3.9	3.9
Yukon Territory	0.8	1.0	0.6	0.4
Manitoba	0.4	0.2	-	-
Unspecified	2.4	4.0	2.1	0.4
Total	71.7	90.0	304.1	333.9

(1) Ranked in order of 1978 expenditures.

(2) These figures exclude expenditures on EMR's Uranium Reconnaissance Program; they include the costs of exploration and surface development, drilling, and all other expenses directly associated with uranium exploration activities, excluding land acquisition. Overhead charges not directly associated with such activities are omitted.

(3) Exploration drilling refers to drilling in search of new uranium deposits or extensions of known uranium deposits and to drilling at the location of a discovery up to the time that the company decides that sufficient ore reserves are present to justify commercial exploitation. Surface development drilling refers to drilling that is done later to determine more precisely a deposit's size, grade and configuration, and excludes drilling of a developing nature on producing properties.

Source: Canada. Energy, Mines and Resources, Canada. 1978 Assessment of Canada's Uranium Supply and Demand. Ottawa, 1979 (Report EP79-3)

a 10-fold increase over 1971 and 1972. They increased to $72 million in 1977 and about $90 million in 1978, almost half of which was in Saskatchewan. In 1978, total reported surface drilling was 333 900 metres, almost 70 percent of which was in Saskatchewan. Although exploration was reported in every province and territory in 1978, Saskatchewan, Quebec, Ontario, British Columbia, and the Northwest Territories accounted for 93 per cent of the drilling (Table 1).

In 1975 Canada's Geological Survey embarked on a 10-year $30 million Uranium Reconnaissance Program to identify all areas in Canada that might be favourable for the occurrence of uranium deposits. Principal activities under the program included airborne gamma-ray spectrometry surveys and regional geochemistry surveys. From 1975 to 1978 a total of $16.6 million was spent on the program. The federal and participating provincial governments spent $4.9 million and $4.2 million in 1977 and 1978 respectively. Federal funding of contract work for this program ceased as of 1979, due to government spending constraints. At that time some 25% of Canada has been covered by the program, an area that represented almost half of the coverage intended over the 10-year program.

Uranium exploration in Canada rests mainly with private enterprise, although the federal government and certain provincial governments compete with private industry through Crown companies. Two provinces, Manitoba and Saskatchewan, have legislated the right of the province to participate (up to 50 per cent) in all new mineral development programs within their boundaries. Manitoba is not currently exercising this right, although it did so in 1977. A wide variety of companies, including both domestic and foreign utilities and firms either controlled or financed by foreign governments, are now involved in uranium exploration in Canada.

In 1978 the Department of EMR did its second annual survey of uranium exploration in Canada. It sent questionnaires to more than 500 companies and individuals known to be exploring for uranium. Of the 116 companies or joint ventures that responded to the survey, including virtually all the major companies known to be active, 77 incured uranium exploration expenditures, and of these, 24 had annual uranium exploration budgets over $1 million. The ten most active companies, accounting for about 60 per cent of Canada's total 1978 exploration expenditures, were as follows:

Company	Dominant Controlling Interests
Saskatchewan Mining Development Corporation	Canada
Uranerz Exploration and Mining Limited	West Germany
Gulf Minerals Canada Limited	United States
E&B Explorations Ltd.	West Germany
Esso Minerals Canada	United States
Urangesellschaft Canada Limited	West Germany
Norcen Energy Resources Limited	Canada
Denison Mines Limited	Canada
Asamera Oil Corporation Ltd.	United States
BP Minerals Limited	United Kingdom

b) Production Phase

Production of uranium in Canada amounted to 6 817 tonnes (U)* in 1979, compared with 6 803 tonnes U in 1978. Seven companies produced ore and six of them had ore processing plants. Shipments from these plants totalled about 6 956 tonnes U in 1979, valued at $664 million. Approximately 64 per cent came from 4 operations in Ontario, and the rest from 3 producers in Saskatchewan. Table 2 shows Canadian uranium ore processing plants and their capacities.

* 1 metric ton elemental uranium (tonne U) is equivalent to 1.2999 short tons uranium oxide (U_3O_8).

Table 2
Canadian Uranium Ore Processing Plants

Plant	Location	Nominal Daily Capacity (tonnes of ore)	Annual Production Rate[1] (tonnes U)
A. Operating			
Agnew Lake Mines Limited	Agnew Lake, Ont.	n.a.[2]	154
Denison Mines Limited - Denison Mill	Elliot Lake, Ont.	6 440[3]	1 880
Eldorado Nuclear Limited	Eldorado, Sask.	1 630[4]	494
Gulf Minerals Canada Ltd.	Rabbit Lake, Sask.	1 500[5]	2 115
Madawaska Mines Limited	Bancroft, Ont.	1 360	210
Rio Algom Limited - Quirke Mill	Elliot Lake, Ont.	6 350	1 950
- Panel Mill	Elliot Lake, Ont.	2 990[6]	-
B. Committed			
Amok Ltd.	Cluff Lake, Sask.	1 360[7]	1 500
Rio Algom Limited - Stanleigh Mill	Elliot Lake, Ont.	4 540[8]	750-900
C. Planned			
Key Lake Mining Corporation	Key Lake, Sask.	460[9]	3 100-4 600
D. Possible[10]			
Brinco Limited	Makkovik, Nfld.	..	..
Consolidated Rexspar Minerals & Chemicals Ltd.	Birch Is., B.C.	..	..
Esso Minerals Canada	Midwest Lake, Sask.	..	..
Norcen Energy Resources Limited	Beaverdell, B.C.	..	..
Rio Algom Limited - Milliken Mill	Elliot Lake, Ont.	..	..

Notes:

(1) 1978 production for operating plants; estimates for others.
(2) Employs an underground and surface heap-leaching technique; to be phased out, beginning September 1979.
(3) To be increased to 13 610 tonnes per day by 1980, an expansion that may increase output by 30 to 50 per cent (by 1985).
(4) Operated at some 1 000 tonnes per day in 1978; full capacity expected by 1980-81, increasing output to about 700 tonnes U/year.
(5) Operating in excess of nominal capacity.
(6) Completed October 1979; expected output about 675 tonnes U/year.
(7) A two-stage program scheduled for completion by 1980-81 and 1983-84, respectively.
(8) Rehabilitation to be completed in 1983-84.
(9) Planned for first production 1983-84.
(10) Feasibility studies in progress or completed, but no firm decisions as to timing and size of operations.

Early in 1979, Canada's seventh producer, Cenex Limited, began operations in the Uranium City area of Saskatchewan. It is a small underground operation which depends upon an arrangement with Eldorado Nuclear Limited for the milling of its ore. By year end, however, the company had gone into receivership due mainly to a fire at its surface facility, and partly also to the marginal economics of its operation. Its future is uncertain. In September 1979, Agnew Lake announced that it would phase out its operations and place its property on a salvage basis, despite the fact that it has the highest average price of any producer in Canada for deliveries from its mill. Since production began in 1977, it has achieved less than 40 per cent of its designed capacity.

Canada's uranium production capability will increase in the short-term because of several major expansion programs underway at existing producing operations and the development of new projects already planned. In Ontario, Denison is expanding its existing operation in the Elliot Lake area and rehabilitating the adjoining Stanrock and Canmet properties to supply domestic and export orders. As well, Rio Algom has recently completed the rehabilitation of its Panel mine and mill and has begun the rehabilitation of its Stanleigh property inactive since 1961, the latter to fulfill a long-term supply contract recently negotiated with Ontario Hydro.

In Saskatchewan, two new projects are potentially of major significance: one at Cluff Lake being developed by Amok Ltd., a French company*, the other at Key Lake being developed by Key Lake Mining Corporation**.

The Key Lake operation is in the final planning stage, its environmental impact statement was released, and the project was examined by a provincial board of inquiry during 1980. It is anticipated that the operation could be in production by 1983 or 1984 if all government approvals can be obtained and if base load contracts are successfully negotiated. Should the Key Lake project be successfully completed, Canada's production capability could be increased to approximately 11 600 tonnes of uranium per year by 1985.

Should markets develop, there are a number of other possible developments which could be supported on the basis of known deposits (Table 2). These include Norcen Energy Resources Limited's Blizzard deposit near Kelowna, British Columbia***; Brinco Limited's Kitts/Michelin deposits in the Makkovik area of eastern Labrador; Esso Minerals Canada's Midwest Lake deposit in northern Saskatchewan; Rio Algom's rehabilitation, as a single production centre, of its Milliken, Lacnor, and Nordic properties in the Elliot Lake area; and possibly Consolidated Rexspar Minerals & Chemicals Limited's Birch Island deposit in southern British Columbia. All of these operations would necessarily have their own processing plants and could add an extra 3 500 tonnes of uranium per year to Canada's production capability by 1990 (Table 3). In view of the poor short-term market situation however, it is likely that development decisions will be deferred in some cases and that the levels of production in Table 3 will not be achieved.

In 1978 the uranium industry in Canada employed about 5 000 workers. Should the industry expand as indicated in Table 3, employment would approximately double by the mid-1980s. Capital expenditures that were committed for this same period were approximately $1 billion. If the uncommitted projects proceed, up to $1 billion more investment will be required. By 1983 the value of Canadian uranium production based on current commitments could approach $1 billion.

---

* This company is jointly owned by Cie de Mokta, Pechiney Ugine Kuhlman, Cie Française de Minerais d'Uranium, and Cie Général des Matières Nucléaires, the latter being a wholly-owned subsidiary of the French Commissariat à l'Énergie Atomique.

** This corporation is jointly owned by Saskatchewan Mining Development Corporation, Uranerz Exploration and Mining Limited, and Eldor Resources Limited, a wholly-owned subsidiary of Eldorado.

*** On February 27, 1980 the Government of British Columbia announced a seven-year moratorium on uranium exploration and mining in the province, thus delaying the development of the Blizzard property for at least seven years.

Table 3
Projected Canadian Uranium Production Capability
(tonnes of uranium per year)

Year	Committed Projects(1)	Uncommitted Projects	Total Capability(2)
1979	6 600	-	6 600
1980	7 000	-	7 000
1981	8 700	-	8 700
1982	9 300	300	9 600
1983	9 500	1 100	10 600
1984	10 900	2 200	13 100
1985	11 600	2 400	14 000
1986	11 700	2 400	14 100
1987	11 400	2 700	14 100
1988	11 800	2 600	14 400
1989	11 700	3 300	15 000
1990	11 700	3 500	15 200

(1) Assumes that Phase II of Cluff Lake project and the Key Lake project will proceed and that expansions of existing facilities will be completed; also assumes the closure of Agnew Lake Mines Limited in 1980.

(2) Based on Reasonably Assured and appropriate portions of Estimated Additional Resources (see Table 8).

Source: Canada. Energy, Mines and Resources Canada. 1978 Assessment of Canada's Uranium Supply and Demand. Ottawa, June 1979. (Report EP 79-3)

Much of the capital for the recent expansion of Canada's uranium industry has been foreign, either directly or indirectly linked to consumers. These funds are usually provided through joint-venture agreements with the foreign partners, in which there is equity participation or provision for a specified share of production or both. In many cases, the foreign partners are wholly or partly-owned state companies or agencies. Several foreign governments, including those of the United Kingdom, France, Italy, Spain, West Germany, and Japan are currently involved in Canadian uranium exploration and development projects.

c) Marketing Phase

The future of the Canadian uranium industry depends mainly on export markets. Of the 6 956 tonnes U shipped by the seven uranium producers in 1979, only about 15 per cent was needed in Canada; the rest was destined for export. Although Canadian requirements will increase significantly over the next 10 years, they will still account for only about 15 per cent of Canada's projected production capability. EMR's 1978 Assessment of Canada's Uranium Supply and Demand estimated that 69 000 tonnes U would be needed to provide the life-time requirements (30 years) for the 14 455 MWe of nuclear electric capacity that were to be in service by 1989. The amount of uranium under contract for domestic needs was over 80 000 tonnes U at the end of 1979. This covers deliveries over the period 1980 to 2020, largely to Ontario Hydro. With recent decreases in Ontario Hydro's nuclear projections, the aggregate requirements to the year 2000 are more than satisfied by current commitments to that time.

Export customers are mainly in western Europe, Japan, and the United States. Deliveries to customers in the United States may become more important as U.S. restrictions on the import of foreign uranium for domestic use are gradually removed between 1977 and 1984. Table 4 indicates the size and distribution of Canadian export contracts as of December 31, 1979. It shows that since September 5, 1974, export contracts totalling about 65 000 tonnes U have been reviewed by the federal government and found to be consistent with Canada's uranium export policy. By the end of 1979 Canadian producers had outstanding export commitments of around 52 400 tonnes of uranium.

d) Refining Phase

Eldorado Nuclear Limited operates Canada's only uranium refinery at Port Hope, Ont. The company converts uranium concentrates (yellowcake), normally containing about 70 per cent uranium, into high purity products used primarily for nuclear purposes. The two main products are natural ceramic-grade uranium dioxide powder (UO_2), used for CANDU reactor fuel fabrication, and natural uranium hexafluoride (UF_6), needed by most of Canada's export customers as feedstock for the uranium enrichment process. Since Canadian uranium export policy stipulates that exports be refined as much as possible, the bulk of Canada's uranium exports are in the form of uranium hexafluoride.

Eldorado's uranium hexafluoride facility in Port Hope is currently one of only five such commercial plants in the world (excluding the Soviet Union, eastern Europe, and China). Two facilities exist in the United States (Allied Chemical Corp. and Kerr McGee Corp.), one in France (Comurhex), and one in Britain (British Nuclear Fuels Ltd.). Competition among these refiners is normally intense, and all of them have expanded in response to the growing market. A new facility is under construction in South Africa, and another is in the planning stage in the western United States.

Table 4
Uranium under Export Contracts reviewed[1] since September 5, 1974

(as of December 1979)

Country	short tons U_3O_8	tonnes U
Belgium	1 220	939
Finland	2 300	1 769
France	2 000	1 539
Italy	1 800	1 385
Japan	25 358	19 508
South Korea	400	308
Spain	6 250	4 808
Sweden	1 025	788
Switzerland	1 050	808
United Kingdom	10 000	7 693
United States	24 850	19 117
West Germany	8 260	6 354
TOTAL	84 513	65 016

Source: Atomic Energy Control Board

1 Reviewed and found to be consistent with Canadian uranium export policy.

In Canada, Eldorado is currently expanding its uranium hexafluoride production capability at its Port Hope plant and, concurrently, is constructing a new refinery near Blind River, Ontario, to produce uranium trioxide (UO_3), the feed material for the UF_6 conversion process. This new plant will permit the phasing-out of UO_3 production at Port Hope. The company also hopes to construct a new UF_6 production facility in Saskatchewan. A site at Warman, near Saskatoon, was seriously under consideration until August 1980. Alternative sites are now being considered. Although Eldorado's plans have the potential to make the company the world's largest producer of uranium hexafluoride by the mid-1980s, the timing of these developments will depend upon the evolution of the market (see Section 3: "Current and Market Prospects").

2. GOVERNMENT POLICY AND REGULATION

a) Regulation:

The Atomic Energy Control Act (AEC) gives the federal government jurisdiction over Canada's uranium industry, although mineral resources are generally under provincial jurisdiction. The Atomic Energy Control Board (AECB) administers the Act by means of a licencing system prescribed in its Regulations. The AECB deals with health, safety, security, and environmental concerns as well as with commercial matters, such as exploration, production, and export.

In November 1977, the federal government tabled a Nuclear Control and Administration Act (Bill C-14) in the House of Commons. One objective of the Bill was to separate the AECB's responsibilities for health, safety, security and the environment from commercial and promotional matters. The provinces took strong exception to many aspects of Bill C-14. At the Federal-Provincial Conference of Mines Ministers in November 1978, Provincial Ministers declared that the Bill perpetuated a federal intrustion into areas which rightfully came under provincial jurisdiction (e.g. exploration and mining, occupational health and safety, and environmental management). The Bill was never passed.

Two recent measures have reduced the AECB's role in regulating commercial matters. First, in August 1979, the AECB ceased to license surface uranium exploration activities, to be consistent with the AEC Act's Regulations, as revised in 1974. Licensing is no longer required unless a company intends to remove from its property more than ten kg of uranium in one calendar year. Second, in October 1979, the chairmanship of the Uranium Exports Review Panel was moved from the President of the AECB to the Assistant Deputy Minister, Energy Policy, in the Department of EMR (the current chairman is the ADM, Conservation and Non-Petroleum). The Panel's composition and purpose did not change. Its members come from the AECB, and the Departments of EMR, Industry, Trade and Commerce, and External Affairs. Its purpose is to review export contracts to ensure that they meet export policy criteria.

b) Ownership:

In June 1978, the federal government tabled the Uranium and Thorium Mining Review Bill (C-64) in the House of Commons. The Bill drew heavily on policy principles first announced in 1970, limiting foreign ownership in the uranium industry. The most important principle was that all new uranium-producing operations in Canada would have no more than 33 per cent non-resident ownership. However, the Bill had provisions to permit non-resident ownership as high as 50 per cent under certain circumstances. Once enacted, the legislation would have been complementary to the Foreign Investment Review Act, and administered by the Minister of EMR. The Foreign Investment Review Agency (FIRA) would have acted as adviser to the Minister, to ensure harmony between ownership and control principles. The legislation would have been retroactive to March 2, 1970. It would have allowed companies to maintain their ownership status if they were in production before this date, or for certain companies, if they submitted documented ownership arrangements predating March 2, 1970. Although the Bill has not been passed or reintroduced, the industry has been observing its intent, because of its retroactivity.

c) Nuclear Safeguards:

Basic to Canada's policy on the export of nuclear technology, equipment and material, is the requirement that these exports be used for peaceful purposes only. For further discussion of this aspect, see "The International Non-Proliferation Regime: an Historical Overview".

d) Domestic Protection:

Although Canadian producers made their first major long-term commercial sales of uranium in 1966 and 1967 the market did not develop in an orderly manner during the late 1960s and early 1970s. This was a period of oversupply, characterized by excess capacity, surplus inventories, and low prices. In late 1973 and early 1974 oversupply began to diminish. The shift from a buyer's to a seller's market was rapid, and there developed intense pressure on Canadian producers. Indeed, in the first few months of 1974, Canadian producers negotiated sales for over 34 000 tonnes of uranium. As a result of this significant export activity the federal government moved to establish more explicit guidelines governing the export of Canadian uranium, to ensure that domestic needs would be met.

These guidelines were published in September 1974. Their two main objectives were:

(1) to ensure a 30-year fuel supply for all those domestic reactors that are operating, committed, or planned for any period 10 years forward;

(2) to ensure that there is sufficient uranium production capacity for the domestic nuclear power program to reach its full potential.

The principal guidelines specified that:

1. all exports must be for peaceful purposes only, and appropriate nuclear safeguards arrangements must be in place;

2. a producer's uncommitted uranium resources must be sufficient to meet its share of the 30-year domestic responsibility;

3. export approvals will be limited to 15 years from the date of contract signing, the last 5 of which may be subject to partial recall;

4. domestic utilities are required to maintain a contracted 15-year forward fuel supply for their operating and committed reactors;

5. all exports of uranium must be processed to the most advanced form possible in Canada, unless special exemption were obtained;

6. export prices offered by any producer will not be more favourable than those under its domestic contracts;

7. the federal government uranium stockpile will only be disposed of in the domestic market and, prior to its disposal, will be available on a commercial loan basis for the short-term needs of Canadian producers and utilities.

There have been only two significant changes in these guidelines. The first relates to the guideline on price (No. 6 above). Upward price trends from 1974 to 1976, and the simultaneous review of contracts with widely different uranium prices, caused difficulty for the export approval process. Early in 1977 the Minister of EMR informed the industry that the government would expect all new contracts to provide for an annual renegotiation of price based on the prevailing market price, with a provision for an escalating floor price designed to protect the producer's investment in its production facilities.

The second change relates to the time limitation on export approvals (No. 3 above). In the case of uranium sales associated with a CANDU reactor export, a CANDU customer may purchase, on normal commercial terms, a 30-year supply of uranium for each reactor. This change was effective early in 1979.

e) International Marketing Arrangement of 1972 to 1975, and Subsequent Events:

To implement Canada's responsibility under the international marketing arrangement*, the Canadian government approved a regulation under Section 9 of the Atomic Energy Control Act authorizing the Minister of EMR to issue Directions to the AECB stipulating minimum selling prices and volumes of sales to export markets. The Minister of EMR revoked all of these quota and price restrictions in January and March 1975, respectively.

By 1976, there were a number of different court actions and investigations underway in the United States, relating to the international uranium marketing activities of 1972 to 1975. Many of these actions had been precipitated either directly or indirectly by Westinghouse Electric Corporation's 1975 revelation that it could not meet a large part of its contracted obligations to supply uranium to its reactor customers**, and resulted in a sweeping demand, through U.S. subpoenas, for information about the 1972 to 1975 international marketing arrangement. While served upon officers of U.S. companies, the subpoenas called for the presentation of information in the possession of subsidiary or affiliate companies "wherever located."

Much of the information sought by the subpoenas was in the files of Canadian companies and it referred to activities approved and supported by the Canadian government. Concerned by the extra-territorial legal implications of the situation, the Canadian government moved to prevent the removal of such documents from Canada by passing the Uranium Information Security Regulations, under the AEC Act, in September 1976. The regulations were amended in October 1977 to provide for a more limited restriction, while ensuring that Canadian sovereignty would continue to be protected.

In October 1977, several opposition members from Canada's Progressive Conservative party challenged the validity of the Uranium Information Security Regulations in the Ontario Supreme Court. While the Court concluded that the Regulations were valid, it ruled that the subsection which gave the Minister of EMR authority to consent to the release of documents covered by the Regulations was invalid.

The Australian government acted through legislation rather than regulation to prevent both the production of documents pertaining to the international marketing arrangement and the enforcement in Australia of judgments rendered in U.S. courts. The extra-territorial implications of several of the U.S. anti-trust actions related to the "Westinghouse Affair", now consolidated in a Chicago court, have been the subject of amicus curiae briefs submitted to the Court by several governments including Canada, the United Kingdom, and Australia. The governments of Australia, the United Kingdom, and France have also formally sought the support of the Canadian government for these actions to limit the availability of documents relating to the marketing arrangements.

In July 1980, the federal government introduced the Foreign Proceedings and Judgments Act (Bill C-41). Under this Bill, where in the opinion of the Attorney General of Canada the recognition or enforcement of foreign judgments in antitrust matters would harm Canada's interests with respect to international trade or commerce, the Attorney General may prevent the recognition or enforcement of such a judgment in Canada, or permit in the case of a money judgment, the recognition or enforcement of that judgment for a reduced amount. The Bill would permit in such cases a Canadian defendant to sue in Canada for and recover from the person in whose favour the foreign judgment has been rendered any amount paid under such unenforceable foreign judgment. The bill would also permit the Attorney General of Canada to prevent the removal from Canada of documents and information in situations where in his opinion a foreign court attempts to exercise extra-territorial jurisdiction in a way that would adversely affect significant Canadian interests with respect to international trade or commerce. Upon promulgation, the bill would repeal the Uranium Information Security Regulations, enacted in September 1976 under the Atomic Energy Control Act, and subsequently amended in October 1977.

---

* See background on pages 1 and 2.

** Paul L. Joskow. "Commercial Impossibility, The Uranium Market and the Westinghouse Case". Journal of Legal Studies 6:119-176, January 1977.

3. CURRENT MARKET PROSPECTS

a) The Growth of Nuclear Energy:

Markets for uranium are linked essentially to its use as a fuel in the production of electricity from nuclear reactors. While future nuclear plans may be subject to uncertainty and constraints, nuclear reactors are already making significant contributions to electricity supply in many countries. Over 100 Gigawatts electric (GWe) of capacity are in place throughout the world (excluding China, USSR, and Eastern Europe).

One of the more recent studies of the long-term growth of nuclear power was carried out within the framework of the International Nuclear Fuel Cycle Evaluation (INFCE), the results of which were released in early 1980*. Sixty-six nations and five international agencies participated in the study over a two year period. The results thus represent a fair consensus of international opinion.

Rather than trying to predict the most probable growth pattern of nuclear capacity, INFCE developed a high and low case, with a wide range between them, reflecting the uncertainty of such projections. The INFCE report noted that these were representative projections rather than limiting bounds and that depending upon decisions and events, both higher and lower capacities are possible. The projections are presented in Table 5. Significantly, since the INFCE projections were finalized, expectations for most countries have continued to decline. Particularly noteworthy in this regard has been the U.S. where there were no new nuclear plant orders during 1979, 6 cancellations, and 69 completion delays. France is one of the few countries where national projections are still the same as those incorporated in Table 5.

Table 5
Projection of World* Nuclear Power Growth
(net Gigawatts)

Year	Low Case	High Case
1980	144	159
1985	245	274
1990	373	462
1995	550	770
2000	850	1 200
2005	1 100	1 650
2010	1 300	2 150
2015	1 450	2 700
2020	1 650	3 350
2025	1 800	3 900

* World excludes the USSR, Eastern Europe and China.
Source: INFCE. Fuel and Heavy Water Availability. Report of Working Group 1. Vienna, January 1980.

* International Nuclear Fuel Cycle Evaluation. Fuel and Heavy Water Availability. Report of Working Group 1. Vienna, January 1980.

Table 6
Annual World Uranium Requirements a), c)
and Production Capabilities to 2025
1000 tonnes U

Year	Low Nuclear Power Growth	High Nuclear Power Growth	Production Capability b)
1980	28	32	50
1985	42	51	94
1990	56	78	116
1995	78	112-116	123
2000	88-108	133-161	115
2005	93-130	146-210	94
2010	94-147	162-262	83
2015	91-164	174-323	66
2020	84-182	181-382	58
2025	74-190	183-430	36

Source: INFCE. Fuel and Heavy Water Availability. Report of Working Group 1. Vienna, January 1980.

Notes: a) Based on a mix of reactor types with the illustrative range referring to strategies with 10 per cent and 54 per cent Fast Breeder Reactors (FBR's) for the upper and lower end of the range, in the case of the high nuclear power growth projection; and with 9 per cent and 51 per cent FBR's for the upper and lower end of the range, in the case of the low nuclear power growth projection.

b) Production levels that could be achieved, under optimum conditions, based only on known resources (i.e. Reasonably Assured and Estimated Additional Resources) plus by-product production from phosphoric acid plants.

c) Requirements assume an enrichment tails assay of 0.20 per cent U^{235}.

b) Uranium Requirements and Availability:

Uranium requirements depend upon not only the expected growth in nuclear power capacity and the mix of reactor types, but also the capacity factors at which the nuclear units are operating and their specific core and working inventories. Another major factor is the assay of the tails stream of the plants used to enrich uranium in its fissionable isotope U^{235}. Variation of the operating tails assay can produce significant differences in the amount of uranium feed required to produce the same amount of product.

Over two dozen illustrative fuel requirement scenarios were developed in the INFCE exercise, for both the high and the low nuclear power growth cases, to produce about 50 projections of uranium demand. Within this wide range of projections, those summarized in Table 6 were considered the most plausible for comparison with supply projections.

Table 6 also shows INFCE's projections of the maximum uranium production levels that can be achieved and supported by the world's known resources of uranium, given optimum conditions. It is estimated that a peak production level of about 123 000 tonnes U per year could be reached by 1995, after which production would decline unless new discoveries were forthcoming. The INFCE report cautioned, however, that the achievement of these production levels would require considerable effort as well as a lessening of certain constraints on the industry's expansion.

c) Short-Term Outlook:

It is useful to examine these projections of future requirements and availability with respect to two time frames. Because the period to 1990 is governed primarily by current developments and plans in the nuclear power industry, it can be gauged with some degree of confidence. The longer term can develop in a variety of ways, depending upon a wide range of possible nuclear power programs using different technologies.

Comparison of the INFCE supply and requirement projections indicates an apparent surplus of uranium supply capability lasting well into the 1990s (see Figures 1 and 2). Notwithstanding certain possibilities for modifying this imbalance, these projections indicate that market opportunities in the short-term will likely be limited and that Canadian producers and potential producers do not have a monopoly on the available market. This scenario implied that some of the potential new uranium producers might need to defer their development plans and that uranium prices could be expected to decline.

Indeed, since the INFCE results became available in early 1980, the short-term outlook has continued to deteriorate. The decline in uranium prices which began in late 1979 accelerated in early 1980. During the first six months of 1980, uranium prices fell by some 25 per cent from a level of $US 104/kg U ($US 40/lb. U^3O_8) to about $US 78/kg U ($US 30/lb. U_3O_8). While the decline was largely attributable to the continuing decrease in market opportunities in the short-term, it was also influenced by sales of utility inventories, particularly in the United States, in the face of rising interest rates. Late-1980 saw no improvement in these conditions and indications were that uranium prices would reach still lower levels.

While the short-term outlook is still uncertain, however, it could shift rapidly in response to various world developments. For example, a resurgence of nuclear plant orders in the United States is conceivable after the 1980 election; continuing increases in the price of petroleum could contribute to increased interest in the nuclear alternative; and disruptions in uranium supply as a result of political unrest in Southern Africa could bring renewed pressure on other sources of supply. Although a resurgence in nuclear power plant orders would provide considerable positive impetus to the uranium market it would provide little benefit in terms of short-term sales, since few of the new plants would be operating before 1990.

d) Longer Term Outlook:

Market prospects seem considerably brighter in the longer term, the degree of optimism depending on the rate of nuclear power growth and the reactor mix assumed (Figure 2A). In an industry where lead times are commonly in excess of ten years, it is essential to consider the possible pattern of growth towards the turn of the century and beyond. The INFCE analysis indicated that additional sources of production would be needed as early as the mid 1990s, and it would be mainly new discoveries that would have to support this production.

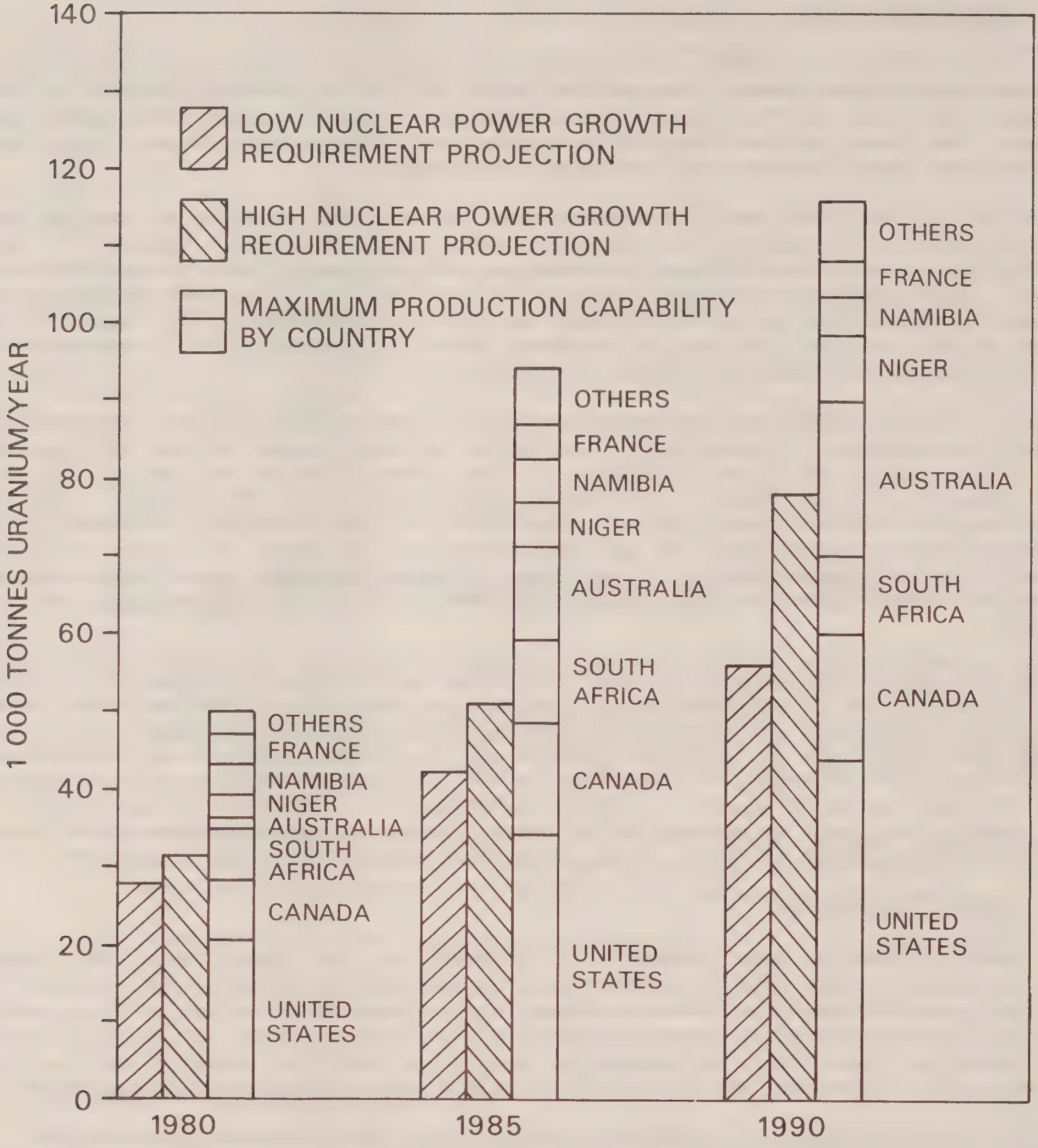
It is very difficult to illustrate meaningfully the required magnitude of future discoveries. A 1977 study* attempted to put future discovery requirements in perspective by using as measuring sticks resource and production capability data for known deposits of different types, sizes and grades. The study's base case uranium requirement was similar to INFCE's high projection in Figure 2A. For this case it was estimated that about 329 new discoveries, representing a mixture of six illustrative mine-types, would be required by the year 2015 to support the production needed by 2020.

---

* Prepared jointly by Atomic Energy of Canada Limited (AECL) and EMR for the Conservation Commission of the World Energy Conference (WEC), See Reference No. 8.

FIGURE 1

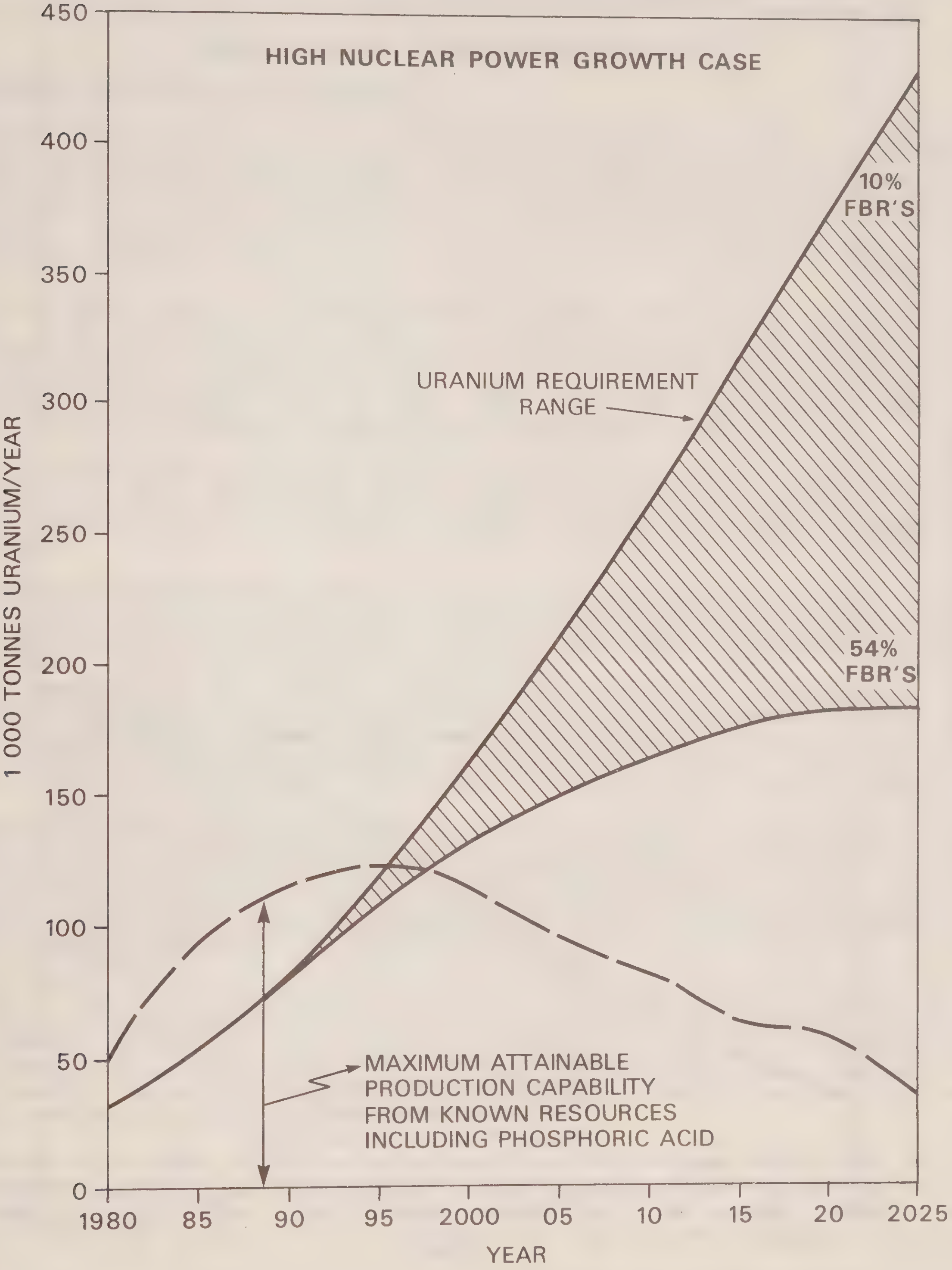
SHORT TERM OUTLOOK
WORLD URANIUM SUPPLY AND REQUIREMENTS



Source: INFCE WORKING GROUP ONE

FIGURE 2A

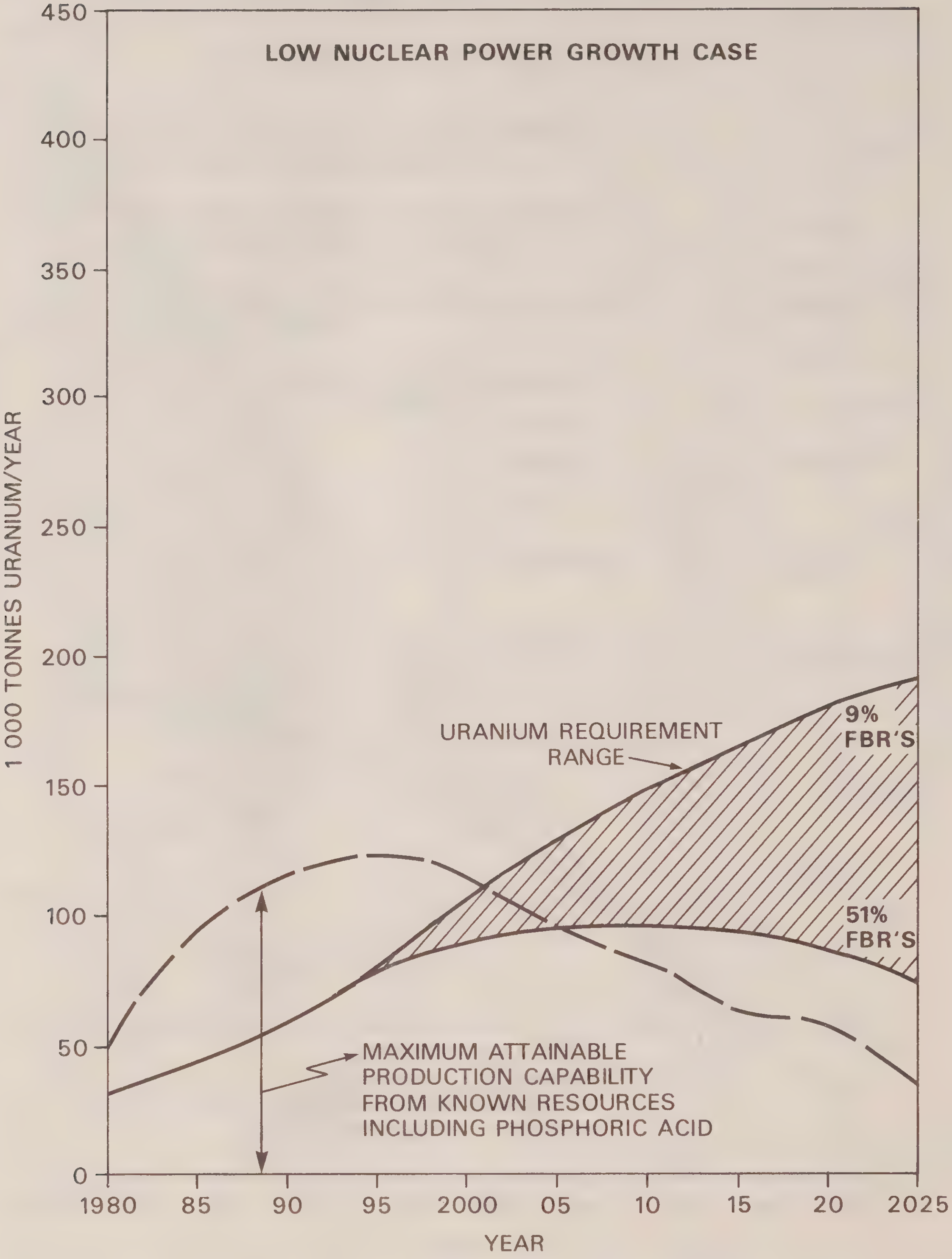
LONG TERM OUTLOOK
WORLD URANIUM SUPPLY AND REQUIREMENTS



Source: INFCE Working Group One

FIGURE 2B

LONG TERM OUTLOOK
WORLD URANIUM SUPPLY AND REQUIREMENTS



Source: INFCE Working Group One

Both the AECL/EMR and the INFCE studies highlight the fact that about 15 years of lead-time elapse from commencement of a uranium exploration program to first production from a successful discovery. It follows that exploration efforts aimed at markets in the late 1990s should be underway in the 1980s. In this context, the illustrative discovery requirements in the AECL/EMR study are truly immense. However, for the longer term market there will be expanding opportunities for the development of successful discoveries.

4. CANADIAN CAPABILITIES AND CONSTRAINTS

Recent figures show that Canada continues to rank among the world's major suppliers of uranium (excluding USSR, Eastern Europe, and China). Canada accounts for about 12 per cent of the world's low-cost Reasonably Assured Resources, standing fourth after Australia, South Africa, and the United States (see Table 7). Perhaps more important to future production capability, Canada has 30 per cent of the world's Estimated Additional Resources, ranking second after the United States.

Canada ranks second to the United States in current world uranium production, estimated around 38 000 tonnes in 1979. Based on known resources, current Canadian production capability of some 7 000 tonnes uranium a year could be increased to over 15 000 tonnes by 1990, then representing perhaps 20 per cent of the world market. Canada is expected to remain the second world supplier until at least 1985; after that time Australia could overtake Canada, should all of Australia's possible developments proceed (see Table 8).

By the early 1980s the value of Canadian uranium production could approach $1 billion. By the mid to late 1980s, the industry may be capable of leading all other sectors of the metal mining industry in value of exports. The impact on Canada's balance of trade could be significant.

Canada's uranium discovery potential is believed to be excellent. Therefore prospects are good that the industry will be able to find the resources to support production capability beyond those levels projected for 1990. As part of EMR's annual uranium resource assessment, the Geological Survey has been assessing this potential for discovery. It believes that Speculative Resources may amount to about 1 to 1.2 million tonnes uranium. These are additional to resources in the Reasonably Assured and Estimated Additional Resource categories. As noted in Section 1, considerable exploration is underway in Canada to realize this potential. Canada's $90 million uranium exploration expenditure in 1978 ranks second in the world after that of the United States, where 1978 expenditures exceeded $US 300 million.

The development of the uranium market is the most important factor determining whether the Canadian uranium industry will achieve the production levels projected in Table 8. There is considerable uncertainty about the availability of markets in the short-term.* However, even if markets exist, insufficient trained workers, equipment and supplies, unsuitable financial arrangements, and delays in the regulatory approval process could constrain production below levels cited for Canada in Table 8.

Time is one of the most important factors affecting the industry's ability to expand. Lead times for uranium exploration and development projects have lengthened considerably in recent years. The lead time from the start of an exploration program to first production from a successful discovery now averages about 15 years, compared with earlier averages of from 8 to 10 years. Increasingly complex regulatory and public inquiry processes have been key factors contributing to these longer lead-times.

Uranium prices have declined markedly since late 1979 and may attain even lower levels before market conditions improve. With the decline in prices, there is some risk that certain of Canada's uranium producers could become uncompetitive. For example, production costs in the Elliot Lake and Uranium City producing areas are high by world standards. Operations in

---

* The discussion in the "Current Market Prospects" section refers.

Table 7
Estimates of Canada's Mineable Uranium Resources, 1978

Resource Category	Mineable at Uranium Prices up to $125/kg U[1]	$175/kg U[2]
	(tonnes U contained in mineable ore)[3]	
(1) Measured	76 000	80 000
(2) Indicated	139 000	155 000
(1) + (2) = Reasonably Assured[4]	215 000 (12%)*	235 000 (9%)*
(3) Inferred	223 000	302 000
(4) Prognosticated	147 000	426 000
(3) + (4) = Estimated Additional[4]	370 000 (25%)*	728 000 (30%)*

1. $125/kg U (Canadian dollars) was the estimated uranium market price in September 1978 at the commencement of the assessment.

2. Includes resources mineable at up to $125/kg U.

3. 1 tonne (metric ton) U = 1.2999 short tons U_3O_8.

4. International resource terms employed by the Nuclear Energy Agency of the OECD and the International Atomic Energy Agency; for purposes of international comparison, Canada compares its high and low "price" categories to the NEA/IAEA's high and low "cost" categories, respectively.

* Canadian proportion of comparable world resource estimates.

Source: Canada. Energy, Mines and Resources Canada. 1978 Assessment of Canada's Uranium Supply and Demand. Ottawa, 1979. (Report EP 79-3)

Table 8

Projection of Annual Production Capability[1] by Country

(1 000 tonnes U)

Country	1980	1981	1982	1983	1984	1985	1990
Australia	0.6	2.3	3.8	5.0	6.5	12.0	20.0
Canada	7.2	9.0	9.9	11.0	13.5	14.4	15.5
France	3.5	3.7	3.9	4.0	4.0	4.0	4.5
Gabon	1.0	1.0	1.5	1.5	1.5	1.5	1.5
Namibia	4.1	4.4	4.6	5.0	5.0	5.0	5.0
Niger	4.0	4.0	4.0	4.0	4.5	6.0	8.5
South Africa	6.5	7.3	8.6	9.9	10.4	10.6	10.4
United States	20.9	24.3	27.1	30.9	33.6	34.1	44.2
Others	2.1	2.9	4.4	5.2	5.5	6.0	6.3
TOTAL WORLD[2]	49.9	58.9	67.8	76.5	84.5	93.6	115.9

1) Maximum attainable production capability from known resources.

2) World excluding USSR, Eastern Europe and China.

Source: NEA/IAEA. Uranium-Resources, Production and Demand. OECD, Paris, 1979.

these areas would likely be the first to be adversely affected. The situations of Cenex Limited and Agnew Lake Mines Limited illustrate this type of financial difficulty*. A prolonged period of low prices would also discourage uranium exploration, probably slowing momentum, and reducing the industry's ability to meet longer-term requirements.

Finally, the uranium industry continues to be troubled by a number of investigations and legal actions, either directly or indirectly related to the "Westinghouse Affair" and the international uranium marketing arrangement of 1972 to 1975. Several Canadian uranium companies are defendants in civil anti-trust proceedings launced in U.S. courts by Westinghouse, as well as by the Tennessee Valley Authority. It is expected that a resolution to these various investigations and court actions will take some time, and that the continued proceedings may constrain Canadian marketing efforts in the United States.

* The discussion of Section 2 "Production Phase" refers.

References

1. Canada. Energy, Mines and Resources Canada. 1978 Assessment of Canada's Uranium Supply and Demand. Ottawa, June 1979. (Report EP 79-3)

2. Runnals, O.J.C. The Uranium Industry in Canada. Brief submitted to the Cluff Lake Board of Inquiry. Ottawa, April 1977.

3. Nuclear Energy Agency of the OECD and the International Atomic Energy Agency. Uranium Resources, Production and Demand. Joint Report. Paris, OECD, 1979.

4. Williams, R.M. "Uranium". In Canadian Minerals Yearbook. Ottawa, Energy, Mines and Resources Canada, 1966 to 1978.

5. Williams, R.M. "Uranium". Canadian Mining Journal 100:133-139, February 1980.

6. Williams, R.M. Market Opportunities for Canadian Uranium. Paper presented to the Seminar on Markets for Canadian Uranium. Calgary, The Canadian Energy Research Institute, October 1979.

7. Uranium Institute. The Balance of Supply and Demand, 1978-1990. London, Mining Journal Books Ltd., February 1979.

8. Duret, M.F., and R.M. Williams, et al. The Contribution of Nuclear Power to World Energy Supply, 1975 to 2020. Volume 2: Nuclear Resources. In: World Energy Resources, 1985-2000. London, IPC Science and Technology Press, July 1978.

9. Joskow, Paul L. "Commercial Impossibility, The Uranium Market and the Westinghouse Case". The Journal of Legal Studies 6;119-176, January 1977.

10. International Nuclear Fuel Cycle Evaluation. Fuel and Heavy Water Availability. Report of Working Group 1. Vienna, January 1980.

AN OVERVIEW OF FEDERAL GOVERNMENT FINANCIAL INVOLVEMENT IN THE CANADIAN NUCLEAR PROGRAM

This paper is based on a draft prepared by T.W. Wallace of the Economic Programs and Government Finance Branch of the Department of Finance.

Summer, 1980

Contents

Tables

Figures

RESEARCH AND DEVELOPMENT

Research and development activities on the use of nuclear energy have been funded from Parliamentary Appropriations since the start of atomic research in Canada. Before 1946 this research was headed by a team of Canadian, British, and U.S. scientists and was mainly directed towards military applications. In 1944 Chalk River was chosen as the site for the construction of the NRX research reactor, which was designed to produce plutonium from uranium using heavy water as a moderator.

After the war, when foreign nationals returned home, it was decided to continue the Chalk River project as a Canadian enterprise. Assets bought for $25.7 million were transferred to the National Research Council, which funded the Chalk River project until 1952. A total of $37.2 million was spent between 1947, when the NRX reactor first went into operation, and 1952, when the assets of the Chalk River project, along with those of the Commerical Products Division of Eldorado Mining and Refining Ltd., were transferred to a newly-formed Crown corporation, Atomic Energy of Canada Ltd. (AECL).

During the rest of the 1950s AECL constructed a second research reactor (NRU) and developed the first nuclear electric generating station in Canada - the 20 MWe Nuclear Power Demonstration (NPD) station on the Ottawa River at Rolphton. Engineers contributed by several Canadian utilities and private industry worked with AECL's engineers and scientists on the design of the nuclear power plant from its beginning in 1954. This team recommended that Canada develop a reactor that used natural uranium as a fuel, heavy water as a moderator, and pressure tubes running the full length of the reactor to contain the fuel and high-pressure coolant -- a proposal that became the basis of the CANDU-PHW system. A team was organized at Canadian General Electric (CGE) in Peterborough to design the NPD reactor as the first demonstration of the concept. CGE put up $2 million for the design work, AECL financed the cost of the nuclear steam supply system, and Ontario Hydro supplied the turbine generator system, the output transformer, switchyard, and transmission lines.

The NRU reactor started up in 1957, while the first electricity was produced from the NPD reactor in 1962. Both of these reactors plus the NRX reactor continue in operation today. The research reactors are used for basic research in neutron physics, for the production of radioactive nuclides for research, medical and commercial uses, and for engineering research supportive of the nuclear power program. The NPD reactor is used for training utility operators and for research and is normally operated as a base-load station supplying power to the Ontario Hydro grid.

In 1959 the decision was made to build the Whiteshell Nuclear Research Establishment (WNRE) at Pinawa, Manitoba. By 1964 a town with over 600 residents had been created. This second research facility has provided many services in the development of the Canadian nuclear program, particularly in matters of radioactive waste disposal and reactor safety. Included among its more significant activities are the design of concrete "canisters" for storage of spent reactor fuel, research on the effects of low levels of radiation on plant communities, and the development of the liquid shut-off rod (an advanced alternative shut-down system). WNRE is also the home of Canada's only organic-cooled, heavy water-moderated reactor (WR-1), which went into operation in 1965.

While the Whiteshell reactor was being built, a design team located in Toronto started work on the design of the Douglas Point reactor. A development laboratory was set up to test fuels, valves, pumps, and other equipment under conditions similar to those of a reactor system. The Toronto group evolved later into the Power Projects Division of AECL and assumed responsibility for the design of all CANDU stations. In 1964 Power Projects moved to its present location in Sheridan Park, and in 1975 opened offices in Montreal.

The establishment and operation of the research laboratories at Chalk River and Pinawa, the construction of the NPD station and the three large research reactors, and the early work of the Power Projects group account for most of the research and development activities funded from budgetary appropriations. Until 1976 grants to universities for research and development

into nuclear energy were also provided through the Atomic Energy Control Board (AECB). The annual appropriations under both of these accounts are shown in Table 1.*

The government's equity contributions in the early years of the CANDU program are shown in the third column of Table 1. The construction of the NRU reactor and part of the Chalk River facilities were first financed by capital stock contributions, that is, by infusions of equity. In 1962-63, however, Parliamentary approval was received for writing off the undepreciated capital cost of the NRU reactor ($25.2 million) as a research expense, and thus the value of the government's equity (then $54 million) was reduced. In the following year a further $13.8 million was received from AECL, reducing the paid-up equity to $15 million.

PROTYPE REACTORS

(1) Douglas Point

By 1959 Canada had the technical competence to build its first large-scale nuclear power plant. A site at Douglas Point in Bruce County, Ontario, was chosen. Agreements were reached with Ontario Hydro for its co-operation in the construction of the plant. The Douglas Point plant, built between 1960 and 1967, was financed by loans from the Government of Canada, which over the eight-year period disbursed a total of $69.9 million (see Table 2).

The Douglas Point reactor is a 208 MWe station moderated by heavy water and cooled by pressurized heavy water. The construction of the plant provided AECL with valuable information that was later incorporated into other units and demonstrated clearly the suitability of the CANDU system for the large-scale production of power. While some technical difficulties arose in the early years of operation, many of those problems have now been overcome. Today the plant is used as a supplier of both steam to the heavy water plant in Bruce County and electricity to the Ontario Hydro grid.

Under the terms of the contract signed between AECL and Ontario Hydro in 1961, it was foreseen that the utility would likely take over the ownership of the plant at a price based on the future value of the power produced. Ontario Hydro is not obliged to buy the plant, however, and has so far not exercised its option. While AECL continues to receive payments for steam and electricity as stipulated under the contract, these payments do not make any contribution to the capital costs of the station. The plant is currently losing money, largely because of its high operating costs and constraints, imposed for reasons of safety, which result in the use of less than 70 per cent of the station's capacity.

In recognition of the plant's inability to pay its capital charges while operating under those constraints, AECL sought and received Parliamentary approval in 1976-77 for the forgiveness of the interest that had accumulated on the Douglas Point debt. In the next year, the outstanding principal amount of the loan of $69.9 million was converted to equity.

(2) Gentilly 1

In response to a request from the Premier of Quebec in 1965, AECL agreed to study the feasibility of building a prototype reactor in Quebec under terms and conditions similar to those of the Douglas Point station. For many years, the potential capital cost advantages of

---

* The practice of recording expenditures and revenues on a cash basis, as viewed from the perspective of the Consolidated Revenue Fund, is followed here. In certain cases, this requires some changes to the figures presented in the National Accounts. In particular, in years in which previous debts are "written-off" as uncollectable, or when interest is forgiven on loans, the National Accounts practice is to record the amounts involved as a budgetary expenditure in the year in which the decision was taken to forgive the debt. These "expenditures", however, do not actually represent a cash outflow in the year recorded, since the monies involved were actually spent in previous years. The practice adopted here is to record expenditures as cash outflows and revenues as cash inflows in the years in which they were incurred. The text then makes clear whether these expenditures and revenues are associated with budgetary appropriations, with loans later forgiven, or with loans still outstanding.

Table 1
Federal Government Expenditures Supporting
Nuclear Energy Research and Development
($ millions)

Year	AECL R&D Expenditures Funded by Appropriations	AECB Research Expenditures Funded by Appropriations	Capital Stock Contributions Financing NRU Reactor and CRNL Facilities	Total R&D Support
1978-79	119.120	-	-	119.120
77-78	128.490[1]	-	-	128.490
76-77	110.058[2]	-	-	110.058
75-76	93.576	11.346	-	104.922
74-75	85.921	10.375	-	96.296
73-74	87.918	7.245	-	95.163
72-73	78.206	7.896	-	86.102
71-72	77.048	11.720	-	88.768
70-71	68.942	7.100	-	76.088
69-70	69.000	5.400	-	74.400
68-69	68.600	3.959	-	71.195
67-68	66.500	2.500	-	69.000
66-67	57.983	2.000	-	59.983
65-66	52.667	1.600	0	54.267
64-65	45.158	1.250	0	46.408
63-64	44.924[3]	.900	-13.761	32.063
62-63	37.062	.770	-	37.832
61-62	33.933	.700	-	34.633
60-61	38.218	.650	-	38.828
59-60	29.408	.650	1.098	31.156
58-59	25.684	.400	4.714	30.798
57-58	21.131	.400	8.863	30.394
56-57	21.544	.300	11.001	32.845
55-56	18.626	.300	12.554	32.886
54-55	14.645	.300	6.967	20.506
53-54	12.360	.300	4.009	16.669
52-53	12.610	.300	4.794[4]	17.704
51-52	12.076	.200	-	12.276
50-51	7.177	.150	-	7.327
49-50	6.618	.150	-	6.768
48-49	5.747	.143	-	5.890
47-48	5.573	.150		5.723
	1556.523	79.154	40.239	2137.148

Source: Public Accounts of Canada

1 Excludes $87.571 million budgetary expenditure covering write-off of Gentilly 1 debt.

2 Excludes $85.491 million budgetary expenditures due to forgiveness of interest on Gentilly 1 and Douglas Point reactors.

3 Excludes $25.239 million budgetary expenditure due to write-off of NRU reactor

4 Non-cash item: Value placed on assets of Chalk River Project on March 31, 1952, when AECL was created.

developing a new CANDU design based on the use of ordinary water (rather than heavy water) as a coolant had been known, and AECL had already determined the technical feasibility of such a process. A decision was thus made to build a 250 MWe prototype reactor based on the "light" water concept on the south shore of the St. Lawrence River.

Work on the Gentilly-1 reactor began in 1966-67 and was financed by loans from the Government of Canada. Although the plant was completed in 1970, it has operated only intermittently due to serious technical problems. At present, it is not operating and would need a major rehabilitation to become a reliable source of power. However, under the terms of the 1966 agreement with Hydro-Québec, the revenue from the power generated by the plant in the future would be clearly insufficient to justify AECL undertaking a large renovation program. Therefore, AECL has been trying to negotiate the sale of the Gentilly 1 plant to Hvdro-Québec, and these discussions continue.

A total of $87.6 million in loans was advanced by the federal government for the construction of Gentilly 1. In 1976-77 the accumulated interest on this debt was forgiven, and in the following year the outstanding principal was written off as a research expense.

(3) Summary

The total federal funds advanced in financing the two prototype reactors are shown in Table 2.

COMMERCIAL REACTORS

(1) Pickering A Units 1 and 2

During 1963-64 AECL studied, for Ontario Hydro, the possibility of scaling up the Douglas Point design to that of a large power station. Experience with operating the NPD reactor and with building the Douglas Point reactor showed that a large project was technically feasible. There remained, though, the basic question of whether the power generated by such a station would be competitive with that produced by conventional coal and oil-fired stations. In view

Table 2
Federal Government Expenditures
on Prototype Reactors
($ millions)

Year	Douglas Point	Gentilly 1
1977-78		5.87
76-77		
75-76		
74-75		
73-74		
72-73		
71-72		4.7
70-71		19.0
69-70		21.0
68-69		22.0
67-68	4.000	12.5
66-67	18.275	2.5
65-66	5.812	
64-65	11.027	
63-64	12.000	
62-63	12.556	
61-62	5.075	
60-61	1.200	
Total	69.945	87.570

Source: Public Accounts Canada

of this economic uncertainty, Ontario Hydro was unwilling to bear all the risks of constructing large-scale plants. The Ontario and federal governments began negotiations on a risk-sharing formula, and in 1963 reached an agreement by which Ontario Hydro would absorb that part of the capital costs equal to the amount which would be spent on coal-fired stations of equivalent capacity while the federal and provincial governments would finance the balance in the ratio of six to five. Under this arrangement, the federal equity (excluding capitalized interest) contributed to the Pickering station amounted to $116.5 million, or 35.7 per cent of the total capital costs.

The 30-year agreement negotiated between the parties specified that if either of the two units failed to operate in a year, or if the operating costs proved higher than those for a reference fossil fuel-fired station, Ontario Hydro's cost penalty would be shared by the equity partners through a "negative payback" to Ontario Hydro from the federal and provincial governments. Balancing this "downside risk" was the provision that any cost savings achieved at Pickering relative to the reference coal-fired station at Lambton would be shared with the partners by a cash "payback" as a return on equity invested.

Pickering units 1 and 2 started up, respectively, in 1971 and 1972. From their inception, these units achieved high capacity factors, and the Pickering station quickly became the showpiece of the CANDU system. With the jump in oil prices in 1973 and later the rise in coal prices, the economic return on the investment proved large. This return was shared by the equity partners in proportion to the risk capital invested. In 1978, for example, AECL received a return of $28 million on the federal equity.

In 1977-78 AECL received Parliamentary Approval to convert to equity the outstanding principal of its borrowings from the federal government for the Pickering investment. This resulted in the cancellation of $79.3 million on the total principal owed by AECL to the government and in the forgiveness of the $38.6 million in interest which had accumulated on these loans. The payback from the Pickering investment now flows directly to AECL, providing it with a source of both cash and profit.

The projected large financial payments from Ontario Hydro to AECL have come under increasing criticism in Ontario during the course of public hearings on the setting of electricity rates. While these payments, which also flow to the Ontario government in amounts almost equal to those of AECL, merely reflect the basic economic benefits of the Pickering units, the provincial utility is anxious to gain complete ownership of the Pickering investment.

(2) Gentilly 2

The equity investment of the federal government in the first two Pickering units was intended to absorb some of the economic risk of the first large-scale CANDU units in Canada. With both Pickering units demonstrating their ability to generate electricity economically, much of the risk that went with the construction of CANDU units disappeared. Accordingly, when Hydro-Québec announced its plans to develop a nuclear power program, the form of federal financial support changed from that of supplying risk capital to that of giving loans at the same borrowing rates available to Crown corporations. Since these rates were marginally lower than those at which utilities could borrow money in the private market, they helped provincial utilities to reduce the capital costs of nuclear generation*.

---

* The differential between the long-term borrowing rates of the Government of Canada and the rates available to provincial utilities has narrowed considerably in recent years. Early in 1975 the federal government rate was about 60 to 100 basis points below equivalent provincial rates; recent bond market quotations indicate a spread of 15 to 30 basis points. The following table indicates the value of the savings in debt service charges accruing to provincial utilities for each dollar borrowed from the federal government, given various interest rate differentials:

cont'd on bottom of next page

In 1973 an agreement was reached with Hydro-Québec by which the federal government would finance 50 per cent of the estimated capital cost of the Gentilly-2 reactor. Support totalling $151 million was extended over the years 1974-75 to 1977-78. The 600 MWe Gentilly-2 reactor is scheduled to begin service in 1981. The agreement was based on an estimated capital cost of $302 million. However, construction costs have escalated sharply since 1973, and today's estimate of the total capital cost is $807 million, including indirect charges. On two occasions, in December 1975 and in January 1978, the Minister of Energy, Mines and Resources (EMR) received a request from Hydro-Québec for a further loan of $150 million to help finance the completion of Gentilly 2. This request was refused both times on the grounds that it would set a precedent for increasing the amount of federal financial support when the costs of a project exceeded the original estimate. The desire of the federal government to avoid open-ended commitments on future as well as existing projects was a central element in this policy.

(3) Point Lepreau

Current federal government policy on financial support for domestic nuclear reactors was established formally in 1973 and 1974 on the basis of the assistance given to Gentilly 2. It states that federal support is available in the form of loans covering 50 per cent of the estimated capital costs of the first nuclear power plant in a province and the second unit if it forms part of a regional interconnection. It also stipulates that a ceiling be placed on the total federal financial commitment.

The first and, to date, only application of this policy arose with the financing of the 600 MWe reactor at Point Lepreau, New Brunswick. In January 1976 a loan agreement between AECL and the New Brunswick Electric Power Commission (NBEPC) was signed. Under the terms of the agreement, the federal government, through AECL, would finance 50 per cent of the estimated construction costs, including interest, with a maximum of $350 million set on its commitment.

As with Gentilly 2, the construction of the Point Lepreau unit is proving more costly than originally estimated. It is now expected that the final cost will be above $900 million. The NBEPC has expressed concern that the federal loan will now cover less than 50 per cent of the cost of the completed unit, and has argued that the reactor poses a considerable financial risk. In the negotiations to make Point Lepreau the first project of the proposed Maritime

---

Value of Savings Resulting From Borrowing One Dollar From Federal Government* as Opposed to Private Market

Interest Rate Differential (basis points)	Annual Saving in Debt Service Payments Per Dollar Borrowed	Present Value of Savings over 30 Years per Dollar Borrowed
15	0.13¢	1.20¢
30	0.27¢	2.38¢
50	0.45¢	3.91¢

These calculations imply that if the federal government supplies loans equal to half the costs of a $1 billion dollar reactor, the annual debt charges to a province would be $.65 to $2.25 million lower than what would be paid by borrowing in the private market. The present value of the savings over a 30-year life equals $6 million to $19.6 million.

* Thirty-year bond: federal borrowing rate of 10.50 per cent.

Energy Corporation (MEC), the NBEPC has asked the federal government to increase its loan commitment and to provide performance and abandonment guarantees.

Although the NBEPC's request was turned down as a package, many of the concerns about the financial impact that Point Lepreau might have on utilities in the Maritimes have been recognized within the context of talks to create the proposed MEC. Concepts being discussed with the Maritime utilities include federal equity participation, a federal government line of credit that could be drawn upon if the Point Lepreau station performs below expectations, and federal government backing of the MEC's borrowings in the private sector through all-events revenue guarantees.

(4) Summary

Total federal financial outlays and repayments for the construction of large commercial reactors in Canada are shown in Table 3. The policies under which this assistance was extended changed as the CANDU program progressed and as economic conditions changed. For the first two reactor units at Pickering, which were built during a period of relatively low inflation, the federal equity investment amounted to 35.7 per cent of the total capital costs. The loans extended to Hydro-Québec and the NBEPC will come to about 15 per cent and 30 per cent, respectively, of the total capital costs. These differences in the percentage of federal support are not the result of deliberate policy decisions as such. They simply reflect the differences that were observed over time in the perceived requirements for federal government investment and in the abilities of AECL, the utilities, and governments to predict total costs accurately and to keep expenses within the original estimates.

All three provincial utilities have asked for changes in the original terms of the agreements. Ontario Hydro has expressed dissatisfaction with the profit earned on the federal government's equity investment, while the Quebec and New Brunswick utilities have sought more financial assistance.

EXPORT REACTOR SALES

(1) India

In 1956 Canada agreed to supply India with a small research reactor (a copy of the NRX reactor at Chalk River). This reactor, named CIRUS, was the first one Canada exported. It was given to India under Canada's foreign aid program and financed by contributions of $9.5 million under the Columbo Plan. The CIRUS reactor began to operate in 1964.

The first export of a commercial reactor was negotiated in 1963, when agreements were reached with India on the construction of a 200 MWe nuclear reactor (RAPP-1). Under these agreements, Canada provided the design, engineering, and commissioning services together with all the necessary equipment and materials. An agreement for the twin of the first reactor (RAPP-2) was concluded in 1966, and its construction began the following year.

Between 1964 and 1969, $33.3 million in loans was extended under the Exports Credits and Insurance Act to finance part of the costs of the RAPP-1 and RAPP-2 reactors. In October 1969 the Export Development Corporation (EDC) was formed, and it took over responsibility for administering all the loans extended previously by the Export Credits Insurance Corporation (ECIC). The loan repayments now flow directly to the EDC and contribute to the annual service charges paid on its consolidated loan account with the Government of Canada.

After the explosion of a nuclear device in India in 1974, and following a period of unsuccessful negotiations, Canada ended further nuclear co-operation with India. This action did not affect the commercial terms of the loan agreement and the EDC continues to receive repayments on that account.

(2) Pakistan

In 1965 agreements were reached with Pakistan on the construction of a 137 MWe nuclear reactor (KANUPP) at Karachi. Canadian General Electric Ltd. was the key contractor in this venture. Financial assistance was provided through credit extended by the ECIC and through

Table 3
Federal Financing of Commercial Nuclear Reactors in Canada -
Cash Outflows, Repayments and Amounts Outstanding
($ millions)

Year	Pickering A Units 1 and 2	Gentilly 2	Point Lepreau
1978-79	-	-	100.0
77-78	-	41.0	60.4
76-77	-15.798	59.0	44.1
75-76	-9.00	31.0	30.0
74-75	-5.490	20.0	
73-74	-6.909		
72-73	10.057		
71-72	20.052		
70-71	28.0		
69-70	22.0		
68-69	19.0		
67-68	9.0		
66-67	6.0		
65-66	2.4		
Total Principal Outstanding	-	151.0	234.5
Uncollected Capitalized Interest	-	0	NYC[3]
Total Amounts Outstanding	-[1,2]	151.0	-[4]

Source: Public Accounts of Canada

1 Outstanding principal of $79.312 million converted to equity of Canada in AECL in 1977-78.

2 Uncollected interest of $38.6 million forgiven in 1977-78.

3 Not yet capitalized (NYC).

4 Drawdown incomplete.

funds of the External Aid Organization (EAO). The ECIC's account was taken over by the Export Development Corporation (EDC) in 1969 and now forms part of the EDC's consolidated loan account with the federal government. Similarly, EAO's account has been taken over by the Canadian International Development Agency (CIDA).

Between 1966 and 1978 a total of $12.4 million was provided in export credits, and $29.4 million was loaned through the EAO/CIDA account. (Grants of about $1.5 million, which covered supervision, training and the financing of spare parts, were also extended by CIDA.) The EAO/CIDA loan was concessionary. Its terms included a 10-year period of grace followed by a 50-year repayment schedule with no interest charges.

(3) Argentina

Canada's first large-scale CANDU export was negotiated with Argentina in 1974. This reactor (Cordoba), which is scheduled for completion in 1980, is being partly financed by a

$129.45 million loan from the EDC under Section 31 of the Export Development Act*. As of December 31, 1978, a total of $117.593 million has been advanced on this account. Under the terms of the contract signed with the EDC, repayments are to start when the reactor begins service.

A further $25 million loan was approved by the EDC in 1978. This loan is being extended under Section 29 of the Export Development Act and is thus at the Corporation's risk.**

The Minister of EMR announced in 1977 that AECL had made provision for losses of $130 million on its reactor sale to Argentina. To date, the cash needed to offset these losses has been met by internally generated funds from services such as the Pickering investment. Therefore, no budgetary appropriations have so far been necessary to cover those losses.

(4) Korea

The EDC has approved a total of $430 million in financing for the nuclear power project in Korea. Of this amount, $250 million was authorized under Section 31 of the Export Development Act; the remaining $180 million, under Section 29. Both loans are to be repaid over 10 years, starting six months after the completion of the project.

(5) Romania

On April 30, 1979, a loan agreement was signed financing the sale of Canadian services and equipment for CANDU power plants in Romania. The agreement provides for up to $680 million in export credits to support up to $1.0 billion in Canadian exports. All this credit was extended under Section 29 of the Export Development Act.

(6) Summary

The net cash flow associated with the financing of nuclear exports is shown in Table 4. As the CANDU program evolved, the nature of this financing changed from contributions under Canada's foreign aid program to loans from the Consolidated Revenue Fund to loans by the EDC from its borrowings in the private sector. Except for the repayments of loans to India and Pakistan, which form part of the consolidated account of the EDC with the Government of Canada, there have so far been no significant repayments to the Fund. The main reason for this is that the construction of the Argentine and Korean reactors is incomplete, and repayments of the loans authorized under Section 31 of the Export Development Act will not begin until these reactors have been put in service.

---

* Section 31 of the Export Development Act is used if, in the opinion of the Board of Directors of the EDC, a proposed loan or guarantee is for a term or an amount greater than that which the EDC would normally undertake for any one export transaction and if, in the opinion of the Minister of Industry, Trade and Commerce it is in the national interest. All monies needed for making loans under this section are paid to the EDC by the Minister of Finance out of the Consolidated Revenue Fund. The EDC maintains a separate account of all monies received by way of receipts and recoveries and repays them to the Receiver General. The Minister of Finance authorizes the EDC to retain from any receipts what he considers to be required to meet the expenses and overhead of the EDC arising out of the loans.

** Section 29 of the Act is used for most of the EDC's lending. Transactions financed under this account are judged on the basis of criteria that would normally be used by a bank in providing an offshore loan to the buyer. These would include present exposure in the borrowing country, the country's balance of payment position and economic climate, the country's record of servicing its debts, and the view of the International Monetary Fund on the borrower's future debt load and credit worthiness. In the early 1970s much of the EDC's activities under this account were financed by borrowings from the Consolidated Revenue Fund. Recently, though, nearly all EDC's activities have been financed through the corporation borrowing on its own account, that is, from private capital markets rather than from the Consolidated Revenue Fund.

Table 4
Federal Financing of Nuclear Reactor Exports

Year	India		Pakistan[1]		Argentina	Korea
	CIRUS	RAPP I&II	KANUPP		CORDOBA	WOLSUNG-1
	(grant)	(loan)	(EAO/ CIDA loan)	ECIC/ EDC loan)	(loan[2])	(loan[2])
1978-79		*		*	32.768	54.346
77-78		*	-.022	*	39.557	44.936
76-77		*	.430	*	37.635	6.158
75-76		*	2.993	*		
74-75		*	2.573	*		
73-74		*		*		
72-73		*	.008	*		
71-72		*	.211	*		
70-71	.036	*	1.160	*		
69-70		*	7.865	*		
68-69		7.838	3.052	9.993		
67-68	.036	11.320	3.789	3.198		
66-67		10.285	4.381	4.578		
65-66		3.239	2.996			
64-65	.194	.640				
63-64	.279					
62-63						
61-62	.279					
60-61						
59-60	1.220					
58-59	1.892					
57-58	4.002					
56-57	1.561					
	9.499	33.322	29.436	17.769	109.960	105.440

Source: Public Accounts of Canada.

1 Excludes about $1.5 million in grants extended by CIDA between 1972 and 1978 to cover supervision, training, and spare part expenditures.

2 Amounts shown reflect disbursements during calender years 1976 to 1978.

* Repayments of loans absorbed into consolidated loan account of EDC with Government of Canada.

HEAVY WATER PLANTS

(1) Glace Bay HWP

In the 1950s Canada imported most of its heavy water from the United States. The decision in 1960 to build a nuclear reactor at Douglas Point, along with indications that it would likely be followed by several more reactors, meant that much greater quantities of heavy water would be needed in Canada. The federal government was anxious to reduce the dependence of the country's nuclear program on foreign sources of supply and to promote the creation of a new Canadian industry. It recognized that a lead-time of two to three years would be needed to get a heavy water facility in operation and that private capital was unlikely to be forthcoming until more reactors, in addition to the one at Douglas Point, were committed.

Thus in 1962 it agreed to underwrite the construction of a heavy water facility by guaranteeing the purchase of 1,000 tons (1100 tonnes) of heavy water over five years at a price of $20.50 a pound. While the government realized that this contract might require it to stockpile heavy water if the domestic reactor program failed to develop as expected, it considered the action justifiable in view of the potential industrial benefits and the security of supply that would result.

In early 1963 bids from several private firms interested in building the heavy water plant were requested. The contract was awarded, later that year, to a joint venture formed between Deuterium of Canada Ltd. (DCL), a private firm, and Industrial Estates Ltd. (IEL), a Nova Scotia Crown corporation, and in 1964 the construction of the plant began at Glace Bay. The Government of Nova Scotia, through the Nova Scotia Power Corporation, provided further support in the form of low electricity rates.

While the Glace Bay plant was designed to produce 200 tonnes of heavy water a year, many of its facilities were planned with the expectation of eventually doubling that capacity. Thus, when the federal government announced, in late 1964, its plans to tender for a new 400-tonne heavy water plant, the decision provoked a strong protest from the Government of Nova Scotia, which argued that priority should be given to underwriting an expansion of the Glace Bay facility. The position of the federal government was that production from a new plant as well as an expanded Glace Bay plant would be needed and that the underwriting of the Glace Bay expansion need only await the negotiation of an agreement.

The discussions between the federal and Nova Scotia governments in 1966 focused on the technical difficulties in bringing the Glace Bay plant into production and on the ability of the province to arrange suitable financing (DCL had no success in tapping the private market). In early 1967 provision was made in the Main Estimates for an advance to Nova Scotia of $16.4 million to help finance an expansion at Glace Bay, beginning when the plant's production had reached the level of 200 tonnes a year (specified in the original contract). This advance was never called upon, however, because severe technical difficulties, including corrosion caused by the sea-water feed, prevented the Glace Bay plant from achieving reliable production while under DCL's ownership.

By 1969 the plant needed an extensive rehabilitation if significant quantities of heavy water were ever to be produced. During the next two years, protracted negotiations between the two governments centered on the federal government's desire to ensure that Nova Scotia accept responsibility for the rehabilitation and on the province's wish to have the federal government assist in the financing. In 1971, following an engineering assessment by AECL which indicated that rehabilitating the Glace Bay plant would be cheaper than constructing a new facility, the federal government directed AECL to take responsibility for repairing the plant.

Under the terms of the rehabilitation agreement, the federal investment was to be recovered through rights to all heavy water produced for 12 to 16 years, after which time the ownership of the plant was to revert to DCL. However, the job of restoration proved much more expensive than originally estimated, and by 1974 it had become apparent that a longer lease period would be necessary if the federal investment was to be recouped at acceptable unit costs for the heavy water produced. Since a longer lease period would likely preclude any return to the original shareholders, it was unacceptable to DCL. In 1978 the parties agreed that AECL would purchase DCL's interest in the Glace Bay plant by installments of $3.3 million a year for 20 years.

The first heavy water was produced at Glace Bay in 1976. However, some technical difficulties demanded further outlays on rehabilitation. Recently, the more significant problems have been overcome, and in 1978-79 the Glace Bay plant produced 210 tonnes of heavy water.

By the end of fiscal year 1978-79, federal outlays to finance the rehabilitation, capital upkeep and maintenance, and the purchase of the Glace Bay plant had come to $191.8 million, excluding interest of $72.9 million. Also, during the period 1970-79 a total of $62.3 million was provided to finance the production of heavy water from the Glace Bay and Port Hawkesbury plants. The amounts advanced yearly under these accounts are shown in Table 5.

(2) Port Hawkesbury HWP

By 1964, after Ontario had announced its intent to build a nuclear power station at Pickering, additional heavy water capacity was needed to meet the expected rise in domestic and foreign demand. Since the long-term market for nuclear power both in Canada and abroad remained uncertain, the federal government offered again to underwrite the first production from a new plant. After the issue of tenders, a contract was awarded to Canadian General Electric Co. (CGE). Under the terms of this agreement, the federal government would buy 5,000 tonnes of heavy water over a period of 12 1/2 years. In 1966 work began on the construction of a 400-tonnes-a-year plant at Port Hawkesbury, Nova Scotia.

Canadian General Electric experienced difficulties in achieving high production levels and was exposed to large cost overruns. In 1971 it expressed its wish to renegotiate the existing fixed-price contract, but this request was denied by the federal government. Later CGE proposed the sale of the plant to AECL. As reasons for its lack of long-term interest in the heavy water business, it cited the difficulties in financing heavy water production and its discomfort in an industry that was becoming largely government-owned. In March 1974, after lengthy negotiations in which the federal government's wish to encourage private investment was balanced by the concern over CGE's willingness to invest sufficient capital, the terms for the sale of the plant were settled. AECL would buy the plant with a $30 million down payment plus a series of installments over ten years (the present value of the purchase price equalled $68.2 million at an interest rate of 7 3/8 per cent).

After AECL bought the Port Hawkesbury plant from CGE, problems arose in securing a reliable steam supply, and a number of renovations had to be made. These capital investments as well as the initial down payment were financed by loans from the Government of Canada. By the end of fiscal year 1978-79, loans advanced to this account amounted to $59 million (see Table 5).

(3) Bruce A HWP

By 1968 Ontario Hydro had announced plans to build four 750 MWe reactors in Bruce County, Ontario. It became apparent that the output from the Glace Bay and Port Hawkesbury plants, neither of which was operating at the time, would be insufficient to supply a large nuclear program in Ontario. The provincial utility approached the federal government for financial assistance to build a 400-tonne heavy water plant at its reactor site in Bruce County, citing the heavy demands its nuclear program was placing on its ability to borrow money in the private sector. Under the agreement reached in December 1968, the federal government would provide loans to finance the plant, AECL would build it, and Ontario Hydro would supply the steam for the plant at cost and purchase the heavy water produced for its Bruce reactors.

In 1969 there were doubts about whether the Glace Bay plant would ever be a reliable producer. At the same time, prospects for export orders were judged to be excellent, though potential customers were becoming increasingly concerned about the availability of heavy water. Because of these changes in supply and demand, the decision was made to double the capacity of the heavy water plant at Bruce and to finance it by loans from the federal government.

Between 1968 and 1973 a total of $175 million was advanced by the federal government, through AECL, for the construction of Bruce A, including an auxiliary steam supply system. The benefit in locating the facility near a large nuclear reactor complex was soon demonstrated because of the plant's access to relatively cheap steam. Bruce A quickly established itself as the most efficient producer of heavy water.

Under the 1968 agreement, Ontario Hydro had the option of buying the Bruce A plant, and it did so in 1975. The price equalled the total federal investment of $253 million, including accrued interest, and is being paid off by installments which flow through AECL to the federal treasury.

With the completion of the Bruce A plant in 1973, the Ontario government approached the federal government again for aid in financing more heavy water plants. Ontario Hydro had launched an ambitious program of expanding nuclear power and was once more concerned about its ability to borrow money. This time, however, Ontario's request was refused because by then

the policy of the federal government was to provide assistance only to the first units in a province. Nevertheless, in the next five years Ontario Hydro undertook both the construction and the financing of two more 800-tonne heavy water plants. (The construction of one-half of one of these facilities - Bruce D - was stopped in 1979, when the forecast load growth in Ontario turned out to be much lower than originally estimated.)

(4) La Prade HWP

By early 1973 it looked as if all the projected output from the Bruce heavy water plant would be needed for Ontario's nuclear program. The conclusion of agreements with Korea and Argentina for the sale of reactors, aside from the reactor already contracted by Hydro-Québec, raised optimism about the future growth in both export and domestic demand, but the experiences at Port Hawkesbury and Glace Bay enhanced doubts about the reliability of supply from these two Cape Breton plants. For these reasons, the federal government decided to build a new heavy water plant. In October 1973 the site at Gentilly, Québec, was chosen. The construction of the 880-tonne heavy water plant was originally scheduled for completion in 1978.

The forecast supply and demand sides of the heavy water market changed radically over the next few years. The introduction of nuclear power into provinces other than Ontario proved much slower than first thought likely as load forecasts were progressively reduced, and the demand for CANDU reactors in other countries remained low. Because of these developments, combined with the government's commitment to restraining its spending, the Treasury Board announced in December 1975 a limit on federal expenditures on the La Prade heavy water plant. This caused the scheduled completion date to be extended to 1981.

By late 1976 the future of the nuclear program in Quebec was in doubt. While the new government in Quebec had not yet altered HydroQuébec's plan to bring a third reactor (Gentilly 3) into operation in 1986, it was reviewing the long-term pace of nuclear development in the province. Since the desirability of continuing to build the La Prade plant under the revised schedule was dependent on Quebec's nuclear program, the federal government approached the Quebec government to discuss its plans for nuclear power. Talks between the two governments continued throughout 1977 and concluded with the signing of two agreements in January 1978. The federal government agreed to proceed with the construction of the La Prade plant on the basis of the new schedule. For its part, the Quebec government undertook to supply steam from the Gentilly-2 plant to the heavy water plant, to bring a third reactor into service by 1990, and to buy the equivalent of three reactor loads of heavy water from the La Prade plant. If this heavy water was not needed in Quebec by 1995, Quebec would have the option of selling the excess back to the federal government.

In August 1978, however, the federal government announced further cutbacks in its spending and indicated its intent to "mothball" the La Prade plant. While this decision did not jeopardize the ability of the federal government to supply heavy water for a nuclear power program in Quebec (indeed, it served to lower the cost of producing heavy water below that which would need to be charged to recover the costs of La Prade), it did require a renegotiation of the agreements signed eight months earlier with Hydro-Québec and the Quebec government. Therefore, the co-operation of the Quebec government in carrying out the federal decision was requested. Consultations between the two governments are still continuing.

Between 1973 and 1979 the federal government advanced $296 million to help build the La Prade plant. An estimated $94 million more will be needed to finish the mothballing process.

(5) Summary

The development of heavy water production capability in Canada has been difficult and costly. The planning process has been complicated by uncertainties about the future demand for heavy water and its sensitivity to public policy decisions, by doubts about the production capabilities of the Cape Breton plants, and by the need to co-ordinate federal investments with the electricity generation expansion plans of provincial governments and their utilities. Most often, policies were decided in circumstances in which the major concern was to alleviate an acute shortage of heavy water. In the last few years, however, the situation has been completely reversed, and emerging surpluses have forced the federal and Ontario governments to mothball plants only partly finished. It is still unclear whether the

rationalization of the industry is complete. Ontario Hydro has indicated its desire and capability to supply heavy water to markets outside Ontario. Such a move could bring the provincial utility into direct competition with AECL.

The total amounts of federal financing extended in building heavy water plants and the repayments (that is, from the Bruce plant) received to date are shown in Table 5. Given the present status of the La Prade plant and the uncertain prospects for future heavy water sales, the recovery of the federal investment will be difficult. As for the Port Hawkesbury and Glace Bay plants, the future return to the federal government will depend on sales of heavy water in the next decade, on decisions about which plants should supply heavy water, and on the price at which this commodity can be sold.

REGULATION AND INSURANCE

(1) Regulation

Since the passage of the Atomic Energy Control Act in 1946, the AECB has had sole responsibility for the regulation of the Canadian atomic energy program. Its basic functions concern the control of "prescribed substances" as defined under the Act (including uranium, thorium, plutonium, other fissionable substances and radioactive isotopes, and deuterium which is commonly used in the form of heavy water) and nuclear facilities in the interest of health, safety, and security. This control is achieved by a comprehensive licensing system which includes the evaluation of an application before the issuance of a permit and later follow-up inspection to ensure compliance.

Annual budgetary expenses covering the regulatory functions of the AECB are shown in Table 6. These outlays were relatively small in the early years of the CANDU program, when few nuclear facilities existed in Canada. In recent years, annual appropriations have increased as the nuclear industry expanded, as international obligations increased, and as the regulatory aspects of waste management and uranium mining received greater priority.

(2) Insurance

The AECB is also responsible for administering the Nuclear Liability Act. This Act received Royal Assent in June 1970 and came into force by proclamation in October 1976. It requires the operators of nuclear installations to carry $75 million in insurance to cover their liability for injury, loss of life, or damage to property resulting from the release of radioactive material. It also provides for re-insurance by the government of any part of the $75 million beyond the ability of the nuclear insurance market and for the establishment of a Nuclear Damage Claims Commission to compensate victims if damages exceed $75 million. The Act is designed to encourage participation in the development of the nuclear industry by limiting the liability of the operator to the required $75 million of insurance and by exonerating all other persons such as architects, suppliers, and contractors.

Premiums received under the re-insurance provisions of the Act are shown in Table 6.

ELDORADO NUCLEAR LTD.

Eldorado Nuclear Ltd. was first incorporated in 1926 as a private company named Eldorado Gold Mines Ltd. In its early years the company mined ore bodies in northern Manitoba and the Great Bear Lake area of the Northwest Territories. It also developed facilities at Port Hope, Ont., to produce radium from mine concentrates. During the Second World War, the federal government, which participated in the Manhattan Project as a supplier of uranium, took control of Eldorado for national security reasons.

The government invested $8.2 million in Eldorado to buy the holdings of the shareholders and finance capital improvements in the late 1940s. Besides re-opening the Port Radium mine, which had closed in 1940, Eldorado began to refine uranium oxide (UO_3) for export to the United States and to explore for uranium. Its explorations led to the discovery of the Beaverlodge ore body in northern Saskatchewan. The mining of this ore, which began in 1953, remains the primary economic base of Uranium City, a community of around 3 000 residents.

Table 5
Federal Expenditures Financing Heavy Water Plant Construction and Heavy Water Production [1]
($ millions)

Year	Heavy Water Plants				Heavy Water Inventory
	Bruce	Glace Bay	Port Hawkesbury	La Prade	
1978-79	-6.29	8.3[2]	9.0	102.5	30
77-78	-5.85		12.0	56.5	2.25
76-77	-5.42	23.0	3.0	37.0	5
75-76	-1.30	33.5	35.0	69.0	15
74-75	0	54.0		31.0	-17.5
73-74	-	55.0			-4.1
72-73	20.0	18.0			11.0
71-72	68.0				10.6
70-71	62.0				0
69-70	25.0				10.0
68-69					
Total Principal Outstanding	156.14	191.8	59.0	296.0	62.25
Uncollected Capitalized Interest	57.094	72.9	NYC[3]	NYC[3]	-
Total Amounts Due	213.23	264.7			62.25

Source: Public Accounts of Canada.

1 The amount shown reflects total advances net of repayments of principal (repayments of interest are included in Table 9).

2 The amount includes a $3.3 million loan to finance 1978 installment payment on Glace Bay purchase.

3 Not yet capitalized (NYC).

Table 6
Expenditures on Atomic Energy Regulation and Premiums Received on Nuclear Insurance
($ millions)

Year	AECB Regulatory Expenditures	Premiums Received on Nuclear Liability Reinsurance
1978-79	14.415	.185
77-78	12.144 [1]	.283
76-77	5.427	.050
75-76	2.648	
74-75	1.622	
73-74	1.132	
72-73	.906	
71-72	.698	
70-71	.597	
69-70	.486	
68-69	.379	
67-68	.302	
66-67	.245	
65-66	.184	
64-65	.157	
63-64	.131	
62-63	.135	
61-62	.079	
60-61	.064	
59-60	.056	
58-59	.052	
57-58	.049	
56-57	.037	
55-56	.039	
54-55	.039	
53-54	.040	
52-53	.035	
51-52	.034	
50-51	.036	
49-50	.035	
48-49	.031	
47-48	.029	
46-47	.012	
	42.275	.518

Source: Public Accounts of Canada.

1 The figure excludes budgetary expenditures of $.641 million to clean up radioactive contamination from the Soviet satellite that crashed in Canada, but it includes $5.143 million for radioactive decontamination of sites in Canada, some of which had no connection with the nuclear power industry.

(Transportation to this isolated town is provided by Eldorado Aviation Ltd., a wholly-owned subsidiary of Eldorado.) During the 1950s, the company also began to refine ceramic grade uranium dioxide (UO_2) for use in CANDU reactors. Eldorado financed all these early activities from retained earnings. Beginning in 1956, it began to pay dividends to the federal government, transferring $32.7 million between 1956 and 1967.

In 1970 Eldorado commissioned a uranium hexafluoride (UF_6) plant in Port Hope to meet the needs of foreign buyers to send their uranium through enrichment plants. In the years around 1970, uranium prices fell, forcing Eldorado to borrow from the federal treasury to sustain its operations. Between 1969 and 1973 it borrowed $48.9 million.

The market for uranium improved slowly, and for a short time repayments on the federal debt were deferred. However, Eldorado is now paying off its debt, with the final payment expected in 1984. At the end of 1978-79, $56.4 million, including capitalized interest of $12.8 million, was still owing on this account.

In 1978 Eldorado, through its subsidiary Eldor Resources Ltd. invested $95.1 million to acquire an interest in the joint venture developing the Key Lake uranium deposit in northern Saskatchewan. The company financed the purchase by selling 769 tonnes of uranium it borrowed from the Government stockpile. Under the terms of this transaction, Eldorado must pay interest on the value of the uranium it borrowed and replace the uranium with production from the Key Lake development.

A summary of the impact on the Consolidated Revenue Fund of those transactions is provided in Table 7.

URANIUM CANADA LTD.

The Canadian uranium industry grew rapidly from the early 1950s until 1959, after which time it declined dramatically because of decisions by the United States and the United Kingdom to avoid taking up options to buy uranium beyond 1963. (The United Kingdom was eventually persuaded to reverse its position.) While the long-term prospects for growth in uranium demand were favourable, the short-term outlook was dismal. Indeed, the possibility that the Canadian industry would collapse completely was real. To ensure the survival of the core of the industry, the federal government took a number of steps to ease the burden on producers, among them the establishment of a one-year stockpiling program.

This stockpiling program lasted from July 1963 to June 1964, but was succeeded in July 1965 by a second, five-year program, owing to the continued depression in uranium demand. These first two stockpiles, which together are referred to as the general stockpile, were financed by nonbudgetary appropriations totalling $101.2 million.

In 1971 the federal government reached an agreement with Denison Mines Ltd, to finance a build-up of reserves of uranium. Under this arrangement, the federal government received a 76 per cent share in what is known as the joint-venture stockpile by paying Denison $4.56 a pound against a book value of $6.00 a pound. A Crown corporation, Uranium Canada Ltd. (UCAN), was formed in that year to represent the government in all commercial activities relating to the purchase, storage, and sale of the uranium stockpile.

During 1972 and 1973 sales agreements were concluded with one Japanese and nine Spanish utilities for about 4 300 tonnes of uranium. The deliveries of those orders exhausted the joint-venture stockpile built up between 1971 and 1974 at a cost to the federal government of $29.1 million and called for the use of a further 1 843 tonnes from the general stockpile. Receipts from those sales (after selling expenses) of about $103 million have been returned to the Consolidated Revenue Fund.

In 1974 the uranium market changed quickly as supplies fell behind demand, causing prices to rise rapidly. In that same year the federal government announced a policy of reserving for domestic use sufficient uranium to provide a 30-year supply of fuel for all existing or committed reactors scheduled for operation 10 years ahead. The policy also specifies that the general stockpile be disposed of solely within the domestic market and, before its total disposal, be loaned to fill any short-term needs of Canadian producers and utilities.

Table 7
Capital Stock Contributions, Loans and Repayments
Arising from Operations of Eldorado Nuclear Limited [1]
($ millions)

Year	Equity Contributions	Loans	Dividends
1978-79		-5.330	
77-78			
76-77			
75-76			
74-75			
73-74			
72-73		12.942	
71-72		8.950	
70-71		9.770	
69-70		17.230	
68-69			
67-68			
66-67			1.0
65-66			1.5
64-65			1.5
63-64			2.0
62-63			3.0
61-62			5.0
60-61			4.935
59-60			4.230
58-59			3.525
57-58			3.525
56-57			
55-56			2.468
54-55			
53-54			
52-53			
51-52			
50-51			
49-50	-1.000		
48-49			
47-48			
46-47	1.032		
45-46	2.943		
44-45			
43-44	5.272		
Total Principal Outstanding	8.247	43.562	32.683
Uncollected Capitalized Interest		12.853	
Total	8.247	56.415	

Source: Public Accounts of Canada

[1] This table excludes the loan for the Key Lake transaction because it had no direct impact on the Consolidated Revenue Fund.

The general stockpile was transferred to UCAN in May 1976. Since then UCAN has loaned uranium to Eldorado Nuclear Ltd. and Ontario Hydro under agreements which provide for interest charges on the value of the uranium borrowed and for repayment-in-kind during the 1980s.

There are, at present, about 5 568 tonnes of uranium in the stockpile or on loan to Canadian producers and utilities. At recent market prices for uranium of roughly Cdn. $130/kg, this stockpile has a nominal value of about $725 million.

The annual cash flows associated with the various stockpiling programs are shown in Table 8.

Table 8
Cash Flows Associated with
Canadian Government Stockpiling Programs
($ millions)

Year	Stockpiling Expenditures	Repayments and Dividends
1978-79		23.814
77-78		10.071
76-77		52.873
75-76		.918
74-75	.116	
73-74	8.615	
72-73	9.044	
71-72	11.396	
70-71	6.562	
69-70	7.385	
68-69	12.280	
67-68	17.794	
66-67	20.093	
65-66	12.656	
64-65	10.877	
63-64	13.537	
	130.355	87.676

Source: Public Accounts of Canada

MISCELLANEOUS

The expenditures and revenues associated with nuclear research and development, reactors, heavy water plants, and the two Crown corporations Eldorado and UCAN account for most of the federal government's involvement in the financing of the Canadian nuclear program. To complete this accounting, it is necessary to include the financial flows arising from some miscellaneous investments by AECL and to indicate the payments of interest received from AECL and Eldorado on the loans extended by the federal government.

(1) Miscellaneous AECL Investments

Since 1954-55 relatively small loan accounts have been kept to finance housing construction at Chalk River and Pinawa, manufacturing facilities for the Commercial Products Division at South March, Ontario, and engineering design offices at Sheridan Park. Annual outlays and repayments under these accounts are shown in the first column of Table 9.

In 1977-78 AECL received an advance of $20 million as working capital. A further loan of $13 million was provided in 1977-78 to finance the purchase of uranium concentrate for lease to Argentina. These transactions are indicated in the second column of Table 9.

(2) Interest Received on Federal Government Loans to AECL and Eldorado Nuclear Ltd.

The schedules of loans and repayments outlined in previous sections excluded both payments of interest made by the federal government on money borrowed to finance the activities of AECL and Eldorado and payments of interest received by the federal government from these two Crown corporations. The interest payments made by the government simply form part of the costs of servicing the public debt and are not segregated in the National Accounts. Those it received are recorded as return on investments and included as a source of government revenue.

The annual interest payments received from AECL and Eldorado are shown in the fourth and fifth columns of Table 9. For the early years, the figures reflect the interest received on the miscellaneous loans just noted. In the last few years, they also include the interest received on the Pickering and Bruce investments, on the advances for financing inventories of heavy water and on the working capital loaned to Eldorado. Unlike the figures in previous tables, however, these amounts do not represent net cash flows, since they are balanced by equal interest payments that service the public debt.

SUMMARY

The annual expenditures and repayments of the federal government associated with the development and exploitation of nuclear power in Canada are shown in Figure 1. For this exposition, the cash flows are broken down into these four areas:

(1) Nuclear Power Development includes all expenditures for research and development, prototype reactors, and regulation. These expenses represent federal government investments in the development and regulation of nuclear technology, and are embodied in the knowledge of Canadians employed in the nuclear industry. The return on these investments consists mostly of cost savings to consumers of nuclear generated electricity and of more jobs for Canadians.

(2) Uranium Industry Support includes all cash flows associated with the operations of Eldorado and with the federal government's stockpiling program. These represent investments in the development and maintenance of a Canadian uranium industry. The returns on the investments are reflected in dividends already received, in the value of the assets of Eldorado and UCAN, and in the present general good health of the Canadian uranium industry. The expected financial returns to the Canadian government from these investments amount to many times the original outlays.

(3) Financing of Nuclear Reactors includes those activities in which the federal government has acted as a banker for the sale of nuclear reactors. While there are small amounts of aid money in this series, the bulk of these expenditures represent basic commercial arrangements. Except for the return on the Pickering investment, which is embodied in the federal government's equity in AECL, the returns from these investments have yet to come.

(4) Heavy Water Production includes all federal lending to support the construction of heavy water plants and the financing of inventory. This series includes the investments in the Bruce A plant, which is now being recovered from Ontario, and in AECL's plants, for which the prospective returns are clearly more doubtful.

Total federal expenditures to support Canada's nuclear power program increased relatively slowly from 1944 to 1964, as shown in Figure 1-e. During this period most federal outlays consisted of budgetary appropriations in support of nuclear power development. Between 1965 and 1970, however, annual expenses increased roughly three-fold. Several undertakings contributed to this increase: the construction of the two prototype reactors, the financing of the Pickering units, the continuation of the stockpiling program, and the financing of nuclear reactor exports to India and Pakistan.

Table 9
Miscellaneous Financial Cash Flows
($ millions)

Year	Loans for Housing, Commercial Products Division and Sheridan Park	Working Capital Advances	Loan Supporting Lease of Uranium Concentrate to Argentina	Interest Received on AECL Loans	Interest Received on ENL Loans
1977-78	-.784	20.0	13.0	24.837	1.393
76-77	-1.083			39.161[1]	
75-76	-.712			15.162	
74-75	-.740			6.116	6.216
73-74	-.416			5.900	
72-73	.070			4.417	1.294
71-72	.381			2.335	1.635
70-71	.911			1.615	.563
69-70	-0.066			1.306	.063
68-69	2.522			.844	
67-68	2.457			.654	
66-67	.589			.559	
65-66	3.683			.403	
64-65	1.011			.348	
63-64	2.163			.236	
62-63	.115			.217	
61-62	-.179			.224	
60-61	.357			.217	
59-60	-.513			.218	
58-59	-.255			.255	
57-58	2.145			.144	
56-57	.372			.145	
55-56	-0.049			.128	
54-55	3.675			.106	Total
Principal Outstanding	15.654	20.0	13.0	105.547	11.164
Uncollected Capitalized Interest	.313				
Total Amounts Outstanding	15.967				

Source: Public Accounts of Canada

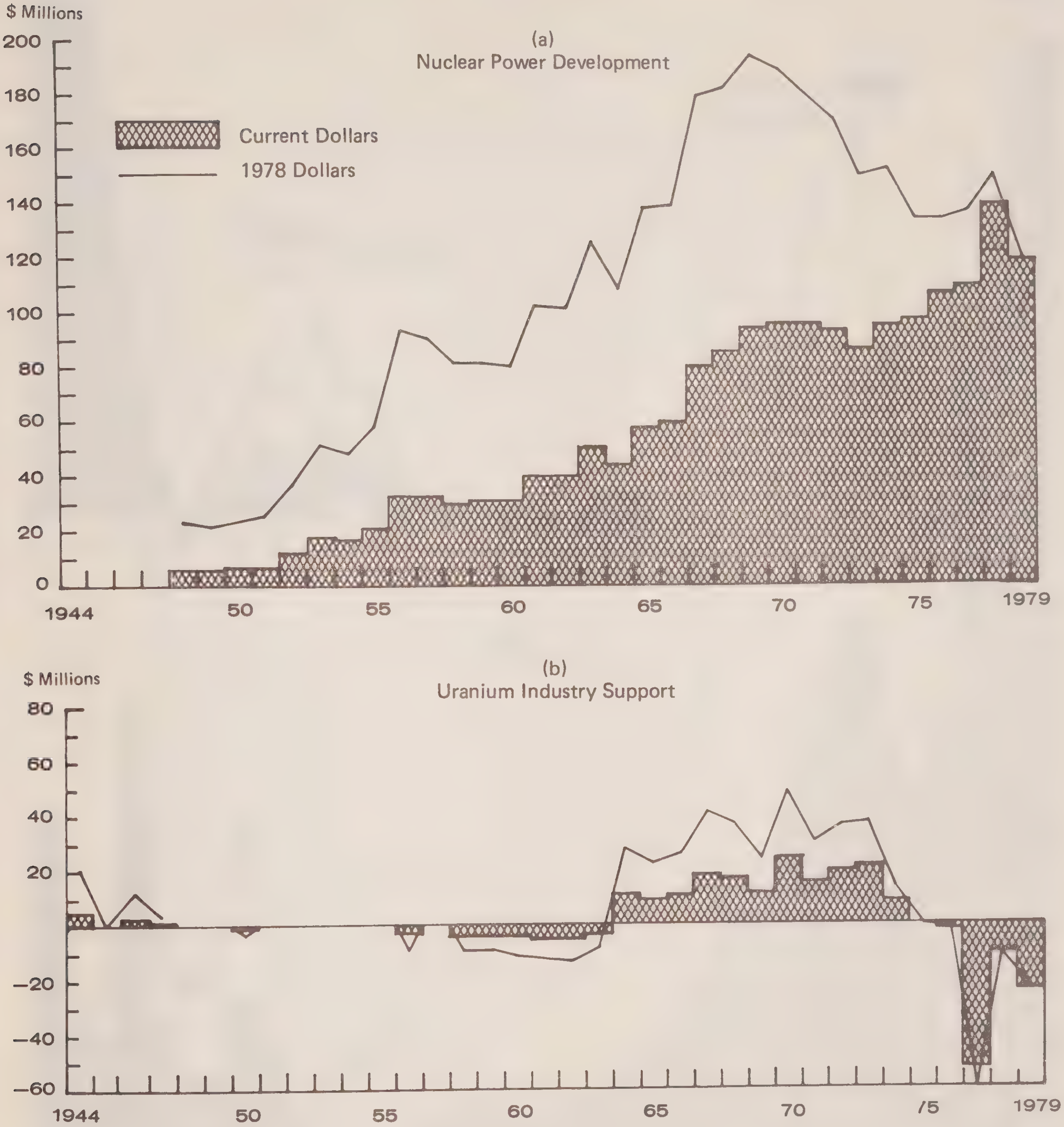
[1] The figure excludes $85.491 million in interest received on prototype loans paid from Parliamentary Appropriations.

In 1978 dollars, annual expenditures under the category Nuclear Power Development peaked in 1970 and fell about 40 per cent by 1979. Since 1970 AECL has concentrated on commercial activities, and the relative requirements for research funding have declined. Policies have also been adopted in the last few years to finance more research through user charges.

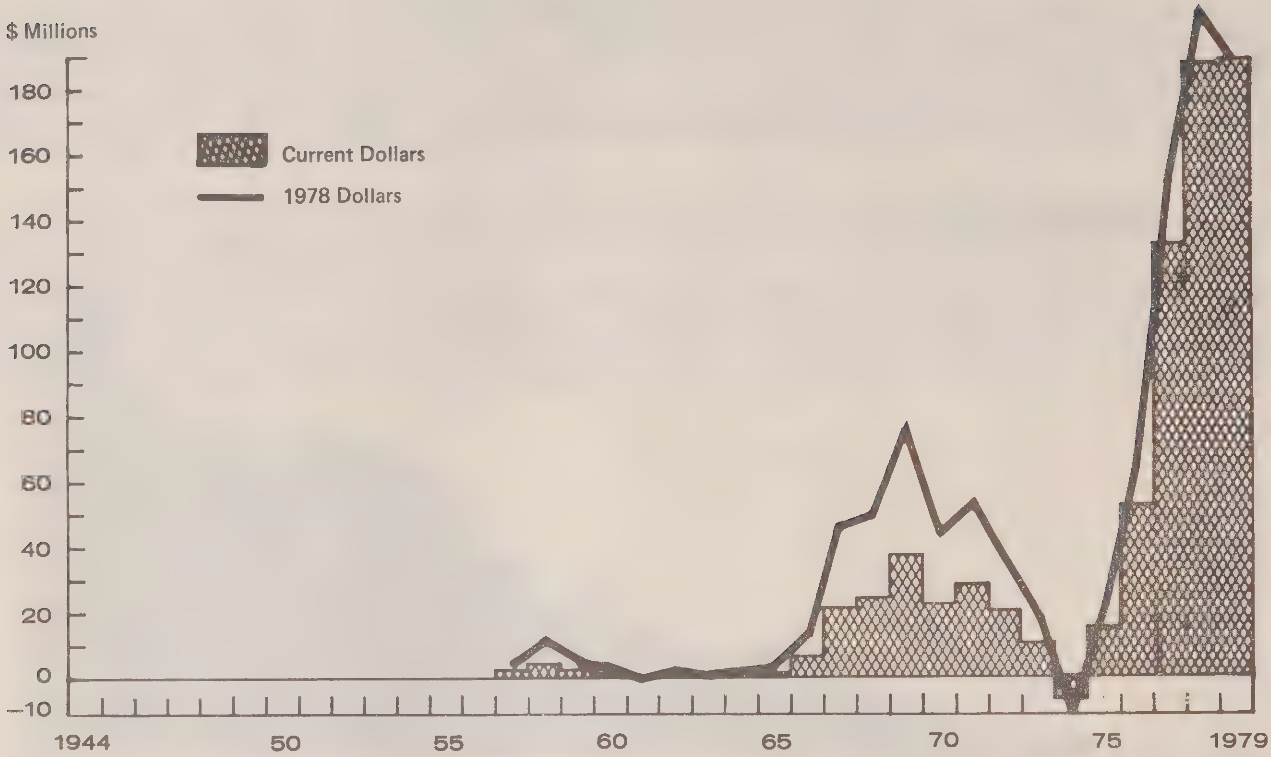
Despite the drop in Nuclear Power Development outlays and the recent repayments under the stockpile program, federal expenditures remained high throughout the 1970s, reaching $430 million in 1978-79. Investments in the heavy water plants of AECL and Ontario Hydro, the establishment of a financing policy for domestic reactors, and the extension of EDC financing (under Section 31 of the Export Development Act) for the Korea and Argentina sales accounted for most federal expenses in the 1970s.

An alternative exposition of the material just presented is shown in Figure 2. Total federal outlays under the aggregate categories are shown on a cummulative basis. Up to 1978-79 total federal expenditures of around $3.4 billion in current dollars have been invested in the development and use of nuclear power in Canada. Of this amount, about 56 per cent was associated with nuclear power development; 2 per cent, with uranium industry support; 22 per cent, with heavy water; and 22 per cent, with financing nuclear reactor sales.

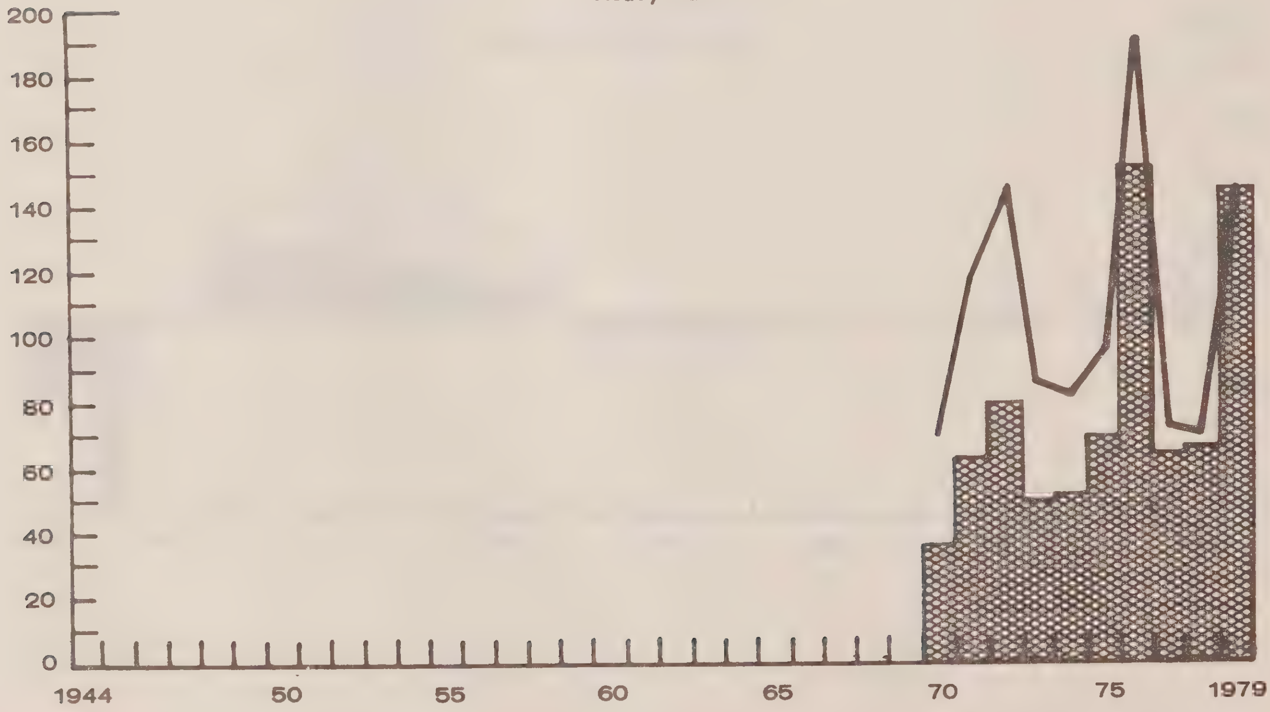
Figure 1
Annual Federal Expenditures (+) and Repayments (−)
Associated with the Development and Exploitation of
Nuclear Energy



(c)
Financing Nuclear Reactors



(d)
Heavy Water



(e)

Total Federal Government Investment

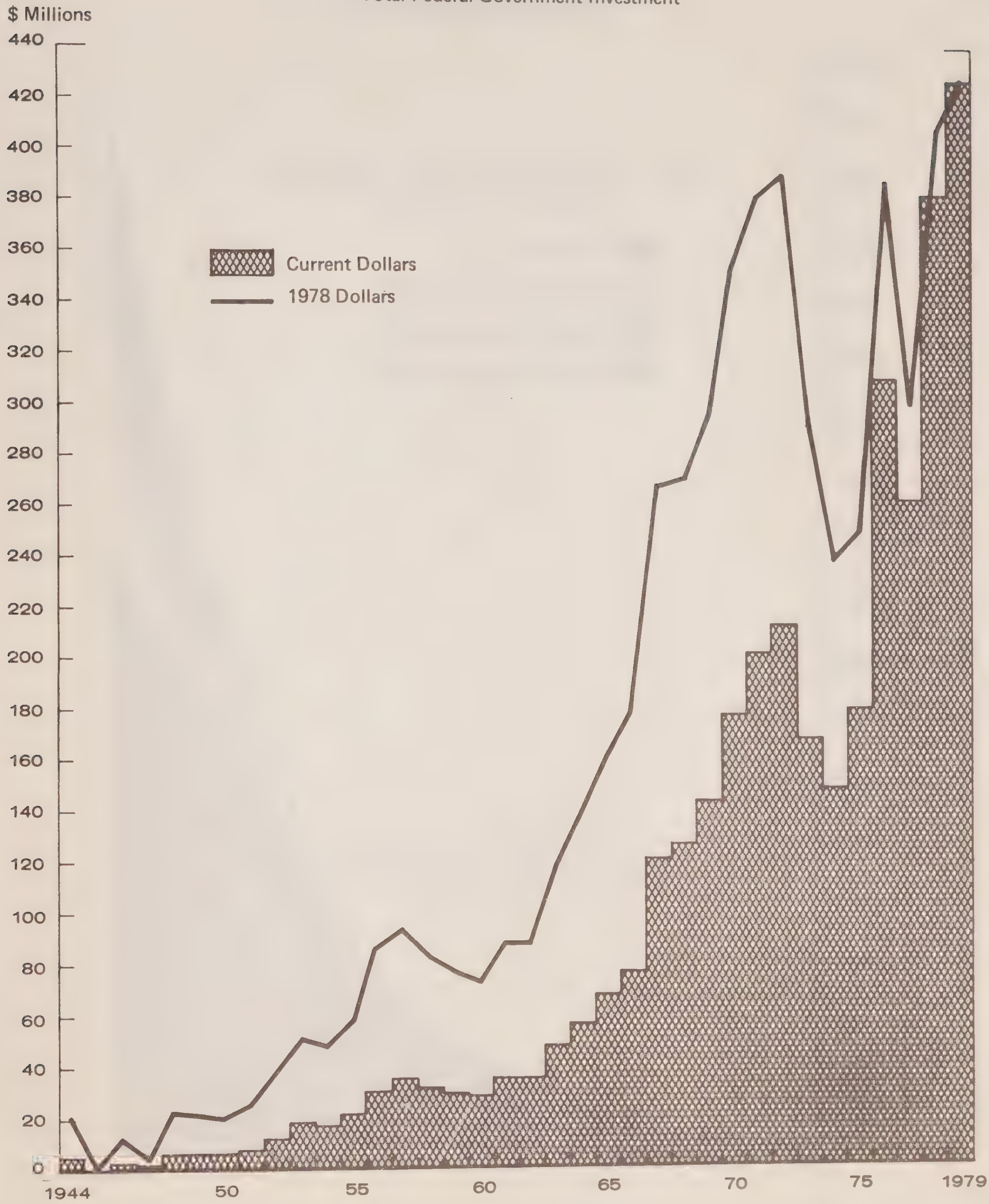
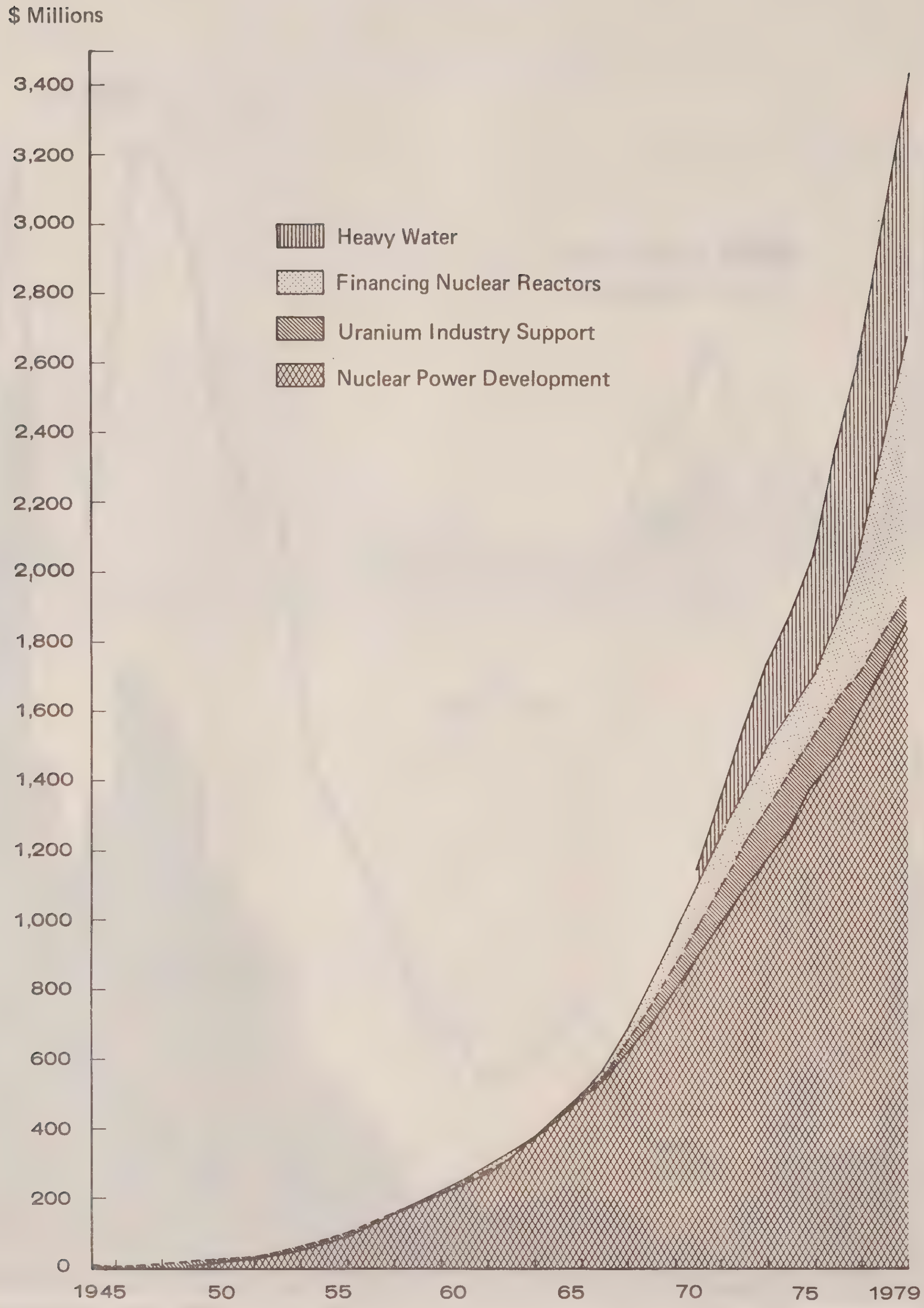


Figure 2
Cumulative Federal Government Investment
in the Canadian Nuclear Program



THE INTERNATIONAL NON-PROLIFERATION REGIME: AN HISTORICAL OVERVIEW

This paper was prepared by
the Department of External Affairs
November 1980

Contents

INTRODUCTION

In the years since 1945 when the first nuclear explosive device was detonated, the international nonproliferation regime has evolved considerably. Its evolution has been divided into two time periods: 1945-1974 and 1974-1980. The three years 1945, 1974, and 1980 mark key turning points in efforts to promote nonproliferation. However, the selection of these dates is not intended to under-rate the importance of the Treaty on the Non-Proliferation of Nuclear Weapons (1968-1970), which is discussed in a separate section.

Before tracing the evolution of the current nonproliferation regime, and of Canada's nonproliferation policy as one part of that regime, a basic observation should be made. International efforts to minimize the risk of nuclear proliferation have taken place against the background of the spread of nuclear explosive capability, from the United States in 1945 and the Soviet Union in 1949 to the United Kingdom and France in the 1950s and the People's Republic of China in the early 1960s. As a result, two types of proliferation have generally been designated: "horizontal" proliferation, which refers to the spread of nuclear explosive capability beyond the five Nuclear Weapon States (NWS) identified above; and "vertical" proliferation, which refers to the growth of the nuclear explosive programs of the five NWS. This discussion deals solely with the evolution of the international nonproliferation regime designed to respond to the threat of horizontal proliferation and, moreover, with only one aspect of this matter.

A risk of horizontal proliferation emerges from the possibility that the nuclear material, facilities, and technology used in research and in the power-generating industry might be diverted or misused to develop a nuclear explosive device. This discussion does not deal with the technology and materials required for nuclear explosives. The measures here discussed to minimize the risk of horizontal proliferation are designed to deter the abuse of the civil nuclear fuel cycle for nuclear explosive purposes. It should be recognized, however, that the civil nuclear fuel cycle is not the most direct nor the easiest route to nuclear weapons or nuclear explosive devices and that, given time and the allocation of sufficient resources, any industrialized country and many developing countries could develop, if they so decided, a nuclear explosive capability.

The risk of horizontal proliferation can be divided into three categories:

(1) Overt: A country announces openly that it is embarking on a nuclear explosive program by drawing upon its civil nuclear fuel cycle or by constructing facilities dedicated to the production of materials for nuclear weapons;

(2) Covert: A country, or possibly a national sub-group, attempts to secretly divert nuclear material from a safeguarded civil nuclear fuel cycle for explosive purposes; or alternatively, it draws on existing technology, skills, and materials to build clandestine facilities;

(3) Theft: A sub-national group steals the material needed for a nuclear explosive device. Such an activity might, of course, be sponsored by the national government of the country where the theft takes place or by another national government.

The objective of a nonproliferation policy, or regime, is to minimize the risk in all three of these categories. The key word is minimize, since it is impossible to remove completely the risk of horizontal proli- feration; there is no "technical fix" to prevent nuclear proliferation. A decision by a government to begin a nuclear weapons program is taken for political reasons, and those reasons can be countered only by other political factors. This aspect of nonproliferation policy is not considered; nor is the problem of clandestine facilities constructed outside the framework of international safeguards. The detection of such facilities can be carried out only by means other than safeguards. Thus, it should be emphasized again that the current international nonproliferation regime discussed here is designed to minimize the possibility that the civil nuclear fuel cycle under safeguards might be used for the production of nuclear material used in nuclear explosive devices.

Within this context, the historical development of measures designed by the international community, and by Canada as a member of that community, to minimize the risk of horizontal proliferation, are outlined.

THE EARLY PERIOD: 1945-1974

The early part of this period, from 1945 to 1957, was a time in which the states involved in the Manhattan Project (the United States, the United Kingdom, and Canada) and others tried to formulate a way of "entirely eliminating the use of atomic energy for destructive purposes and promoting its widest use for industrial and humanitarian purposes" (Agreed Declaration on Atomic Energy, November 1945). In January 1946, after discussions among the United States, the United Kingdom, and the Soviet Union, the United Nations passed a resolution creating the U.N. Atomic Energy Commission. Meanwhile, the United States adopted a national policy on atomic power which was reflected in its Atomic Energy Act of 1946 and which placed an embargo on the export of nuclear materials and information.

During these years, however, it became evident that it would not be possible to prevent the spread of nuclear technology. This fact was recognized in the Report on the International Control of Atomic Energy (the Acheson-Lilienthal Report), which was prepared by a group under the leadership of Dean Acheson and David Lilienthal. President Eisenhower's speech to the U.N. General Assembly in December 1953 proposing the establishment of an international agency which would be devoted entirely to the peaceful use of nuclear energy marked a further step in this process. On December 4, 1954, the General Assembly unanimously adopted an Atoms for Peace resolution calling for the establishment of such an agency. After two years of negotiations, the Statute of the International Atomic Energy Agency (IAEA) was unanimously approved and signed in October 1956. It came into force on July 29, 1957.

Under Article II of the IAEA Statute, "the Agency shall seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world. It shall ensure, so far as it is able, that assistance provided by it or at its request or under its supervision or control is not used in such a way as to further any military purpose." Article III describes the functions which the Agency is authorized to carry out. Article III.A.5 has particular significance for nonproliferation. It authorizes the Agency "to establish and administer safeguards designed to ensure that special fissionable and other materials, services, equipment, facilities, and information made available by the Agency or at its request or under its supervision or control are not used in such a way as to further any military purpose; and to apply safeguards, at the request of the parties, to any bilateral or multilateral arrangement, or at the request of a State, to any of that State's activities in the field of atomic energy."

Under Article III.A.5 of the IAEA Statute, the Agency began to establish and administer a system of safeguards to cover all material provided by or through it and any nuclear activities for which the application of international safeguards had been requested. By 1968 it was administering international safeguards under agreements with about 28 states. At the time, a central feature of the nonproliferation regime was that the Agency applied safeguards only in response to voluntary requests from its member states. The states had no obligation to make such requests to cover indigenously developed nuclear activities or imported nuclear materials, equipment, and technology.

Thus international efforts to promote nonproliferation in the post-1957 period were based on the two principles first written in the November 1945 Agreed Declaration on Atomic Energy and later incorporated into the Statute of the IAEA: to eliminate the use of atomic energy for destructive ends, and at the same time to promote its use for industrial and humanitarian purposes. Since then, efforts to support the nonproliferation goal have been dominated by the question of how to achieve a proper balance between measures to advance these two principles.

THE TREATY ON THE NON-PROLIFERATION OF NUCLEAR WEAPONS (NPT)

By 1965 five states had nuclear arms, and there were signs that more states were moving toward acquiring such weapons. As early as 1958, Ireland had submitted a resolution at the U.N. General Assembly expressing concern over this trend. Growing international concern finally resulted in the negotiation of the 1968 Treaty on the Non-proliferation of Nuclear

Weapons (NPT). By 1970, 40 countries, including three NWS (the United States, the United Kingdom, and the Soviet Union) had ratified the NPT, which then became effective on March 5 of that year.

The NPT had built into it a distinction between Nuclear-Weapon States (NWS) and Non-Nuclear-Weapon States (NNWS) which recognized the unique status of the five states (the United States, the Soviet Union, the United Kingdom, France, and the People's Republic of China) which had manufactured and exploded a nuclear weapon before January 1, 1967. Many states viewed this distinction as discriminatory because the obligations placed on NWS and NNWS parties to the NPT are significantly different. NWS do not have to accept international safeguards (although the United States, the United Kingdom, and France have moved in this direction), while NNWS are required to accept safeguards on all source or special fissionable material under their control. However, under Article VI of the NPT, NWS obliged themselves to pursue negotiations in good faith on effective measures relating to the early cessation of the nuclear arms race and to nuclear disarmament.

In the context of horizontal proliferation, five aspects of the NPT are particularly noteworthy:

(1) the binding commitment by NWS party to the NPT not to transfer to any recipient nuclear weapons or other nuclear explosive devices or control over such weapons or devices or to encourage or assist any NNWS to manufacture or acquire such weapons or devices (Article I);

(2) the binding commitment to nonproliferation made by NNWS party to the NPT (Article II);

(3) the commitment by NNWS party to the NPT to accept safeguards on all source or special fissionable material in all peaceful nuclear activities carried out by that State (Article III.1);

(4) the recognition of the right of all NNWS party to the NPT to participate in the fullest possible exchange of equipment, materials, and scientific and technological information for the peaceful uses of nuclear energy (Article IV.1);

(5) the obligation of all parties to the NPT to facilitate, and their right to participate in, the fullest possible exchange of equipment, materials, and scientific and technological information for the peaceful uses of nuclear energy.

Thus the principles of the November 1945 Agreed Declaration and the IAEA Statute were reflected once again in an international agreement.

By August 1979, three NWS and 107 NNWS, including 31 NNWS with significant nuclear activities, had become parties to the NPT. At present, 10 NNWS which have substantial nuclear activities (Argentina, Brazil, Chile, the Democratic People's Republic of Korea, India, Israel, Pakistan, South Africa, Spain, and Turkey) are not parties to the NPT, and in four of these countries (India, Israel, South Africa, and Spain) as well as in Egypt (which has signed but not ratified the NPT) unsafe- guarded nuclear facilities are in operation. Therefore, while the NPT initiated a significant expansion of IAEA safeguards operations and marked a major step forward in efforts to promote nonproliferation, there remains the need for continued work by the international community to encourage accession to this treaty.

Within the approach to nonproliferation entailed in the IAEA Statute and later in the NPT, much nuclear co-operation has developed between industrialized and developing countries. A result of this co-operation can be seen in the number of states (43) which are now carrying out nuclear activities under IAEA safeguards.

The First NPT Review Conference, as provided for under Article VIII of the NPT, was convened in May 1975 to review the operation of the NPT to ensure that the objectives of the preamble and provisions of the Treaty were being achieved. While the Conference recognized the continuing importance of the NPT and affirmed the belief that universal adherence would greatly strengthen international peace and enhance the security of all states, it also expressed the firm conviction that to achieve those goals it was essential to maintain, in the implementation of the Treaty, an acceptable balance between the mutual responsibilities and

obligations of all NWS and NNWS parties to the Treaty. The Conference expressed serious concern that the nuclear arms race was continuing unabated and urged constant and resolute efforts by all states, particularly the NWS, to achieve an early and effective implementation of Article VI of the Treaty.

The Review Conference reached a number of significant conclusions on the horizontal nonproliferation provisions of the NPT, primarily Articles III and IV:

(1) that the IAEA's safeguards operations respect the sovereign rights of States and do not hamper economic, scientific or technological development or international co-operation in peaceful nuclear activities;

(2) that in all achievable ways common export requirements relating to safeguards should be strengthened, in particular by extending the application of safeguards to all peaceful nuclear activities in importing States not Party to the Treaty;

(3) that such common requirements should be accorded the widest possible measure of acceptance among all suppliers and recipients;

(4) that action should be pursued to elaborate further, within the IAEA, concrete recommendations for the physical protection of nuclear material in use, storage, and transit.

On Article IV, the Conference reaffirmed that the NPT did not affect the inalienable right of all parties to the Treaty to develop nuclear energy for peaceful purposes without discrimination. It also re-affirmed the undertaking by all parties to facilitate the fullest possible exchange of equipment, materials, and scientific and technological information for the peaceful uses of nuclear energy. The Conference expressed the conviction that further efforts should be made to ensure that the benefits from the peaceful application of nuclear technology should be made available to all parties to the Treatv, and advocated increased technical assistance to help developing states.

Therefore, the First NPT Review Conference concluded with a re-affirmation by states party to the Treaty of their common interest in nonproliferation and in co-operation in the peaceful uses of nuclear energy under adequate safeguards. There were some expressions of concern, however, that efforts to slow down or halt the nuclear arms race had not been successful and that co-operation in the peaceful uses of nuclear energy had not been as forthcoming as expected by some states.

The Second NPT Review Conference took place in Geneva from August 11 to September 5, 1980. This Conference was less successful than the First Review Conference as failure to reach agreement on nuclear disarmament questions led to the Conference being unable to adopt a final document. Agreement on a compromise draft text dealing with the sections of the NPT concerned with the peaceful uses of nuclear energy (Article 4) and horizontal nonproliferation (Article 3) was possible even though there was considerable dissatisfaction among the developing countries over the adoption by the major nuclear suppliers of nonproliferation requirements (e.g., the Nuclear Suppliers Group Guidelines) which went beyond those posed by the NPT. The developing countries also perceived a failure by the developed countries to implement Article IV of the Treaty by provision of increased technical assistance and other means. It is hoped the international dialogue initiated in INFCE and envisaged to continue in the IAEA's Committee on Assurances of Supply (CAS) (see page 23) will result in a better understanding of the respective concerns of these two groups of countries.

CANADA: 1945-1974

Canada, as noted earlier, was one of the three states that participated in the November 1945 Agreed Declaration on Atomic Energy. Throughout the years that followed, Canada played an active and significant role in efforts to define an international regime which would serve the twin principles set forth in that Declaration. Hence Canada participated both in the

drafting of the IAEA Statute between April 1955 and October 1956 and in the Preparatory Commission appointed to make arrangements for the first sessions of the IAEA's General Conference and of its Board of Governors. Canada has had continuous representation on the Board of Governors since the founding of the IAEA and has strongly supported the Agency's efforts on nuclear safeguards. Canadian representatives were also involved in the negotiations of the Treaty on the Non-proliferation of Nuclear Weapons.

While participating in the efforts to define an international nonproliferation regime, Canada's policy on horizontal proliferation evolved. This evolution reflected both international developments and the emergence of Canada's own nuclear technology.

At the end of the second world war, Canada shifted its efforts from the weapons-oriented Manhattan Project to research and development for peaceful applications, to radionuclide production, and to the development of a commercial nuclear reactor for the generation of electricity. The Canadian government pledged voluntarily that it would not develop nuclear weapons. (For detailed discussions of the development of the Canadian nuclear industry over the past 30 years, see "The Structure of the Canadian Nuclear Industry" and "Federal Government Financial Involvement in the Canadian Nuclear Program; An Overview".) As knowledge, experience, and awareness of nuclear technology increased in Canada and elsewhere, and as vertical proliferation took place through the 1950s and early 1960s, successive Canadian governments revised Canada's policy to minimize the risk that Canadian nuclear co-operation would contribute to nuclear proliferation.

Early in the 1945-1974 period Canada's interactions with other countries on nuclear matters were in two main areas: uranium exports and continuing technical co-operation with its wartime partners. However, as its reactor technology developed, Canada entered into agreements with several other countries for the transfer of that technology and related material and equipment. By 1974 Canada had exported research reactors to India and Taiwan, power reactors to India and Pakistan, and had signed a contract for the export of a 600 MWe power reactor to Argentina. Discussions had also taken place concerning the sale of a power reactor to the Republic of Korea.

(1) Uranium Exports

Canada's uranium exports during the 1945-1974 period were carried out under nuclear co-operation agreements (Canada-Federal Republic of Germany in 1957; Canada-Switzerland in 1958; Canada-Euratom in 1959; Canada-Japan in 1959; Canada-Sweden in 1962) which made Canada's uranium exports subject to a "peaceful uses" commitment and to acceptance by the importing country of bilateral verification measures by Canada or, increasingly, of IAEA safeguards.

From 1945 to 1965 Canada also exported uranium to the United States and the United Kingdom for use in their nuclear weapons programs. These export sales were carried out as part of Canada's defence relationship with those two countries. This policy was ended in June 1965, when Prime Minister Pearson announced in the House of Commons that:

> "as one part of its policy to promote the use of Canadian uranium for peaceful purposes the Government has decided that export permits will be granted, or commitments to issue export permits will be given, with respect to sales of uranium covered by contracts entered into from now on, only if the uranium is to be used for peaceful purposes. Before such sales to any destination are authorized the Government will require an agreement with the government of the importing country to ensure that appropriate verification and control that the uranium is to be used for peaceful purposes only."

With the announcement of this policy, all Canadian uranium exports became subject to a "peaceful uses" provision.

(2) India

In 1956 Canada concluded an agreement to supply a research reactor to India as part of its aid program to that country. This reactor, the CIRUS reactor, was provided subject to assurances that it would be used for peaceful purposes only. The United States provided the heavy water for this reactor. The provision of this reactor and subsequent nuclear co-operation between Canada and India was a concrete demonstration of Canada's desire to promote the principles later set forth in the IAEA Statute and the NPT regarding the transfer of nuclear materials, equipment, and technology for peaceful uses.

In 1963 Canada and India concluded an agreement for the construction of the first unit of a nuclear power station called the Rajasthan Atomic Power Plant (RAPP-1). Under this agreement, India committed itself to using the fissionable material produced in the RAPP-1 reactor "only for peaceful purposes" and agreed that Canadian technical experts could verify this undertaking. In 1966 a second CANDU unit (RAPP-2) was sold to India. In a Canada-India-IAEA agreement concluded in 1971, the IAEA assumed the responsibility for the verification provided for by the Canada-India agreement.

During the early 1970s Canada's concern that the plutonium contained in the fuel irradiated in the CIRUS reactor might be used for explosive purposes led Prime Minister Trudeau to write to Prime Minister Indira Gandhi in October 1971 to clarify Canada's views on "any further proliferation of nuclear explosive devices" and to state that "the use of Canadian supplied material, equipment and facilities in India, that is, at CIRUS, RAPP I or RAPP II, or fissile material from these reactors, for the development of a nuclear explosive device would inevitably call on our part for a reassessment of our nuclear cooperation arrangements with India." In response, Prime Minister Gandhi agreed that the nuclear co-operation between Canada and India had been dedicated to "the development and application of nuclear energy for peaceful purposes", but added that "it should not be necessary now in our view to interpret these agreements in a particular way based on the development of a hypothetical contingency".

On May 18, 1974, India detonated a nuclear explosive device, claiming it was solely for peaceful purposes, that is, a "peaceful nuclear explosive" (PNE). The Canadian government, which does not distinguish between nuclear weapons and nuclear explosives, immediately suspended its nuclear co-operation program with India. Later India admitted that plutonium produced in the CIRUS reactor using uranium fuel of non-Canadian origin had been used in that explosive device. It continues to maintain, however, that since nuclear material of non-Canadian origin was used, there has been no breach of its undertakings to Canada.

(3) Pakistan

In 1959 Canada signed a nuclear co-operation agreement with Pakistan covering the provision of a 125 MWe CANDU-type power reactor (Kanupp). The agreement was similar to that concluded later between Canada and India for the RAPP reactors. In 1969 Canada, Pakistan, and the IAEA concluded an agreement under which the IAEA assumed the responsibility of safeguarding the Kanupp reactor. The reactor began commercial operation in 1972.

(4) Taiwan

In 1969 Canada sold to Taiwan a 40 MWe nuclear research reactor, the Taiwan Research Reactor (TRR), complete with heavy water and fuel. This sale was conditional on Taiwan's concluding with the IAEA a safeguards agreement by which Taiwan would undertake not to use the TRR reactor in such a way as to further any military purpose. Despite the change in Taiwan's status in relation to the IAEA, this agreement continues in effect, and the TRR reactor remains subject to IAEA safeguards.

(5) Argentina

In December 1973, Atomic Energy of Canada Ltd. (AECL) and the Comision Nacional de Energia Atomica (CNEA) signed a contract for the supply of one 600 MWe CANDU reactor to Argentina together with the fuel, heavy water, and technology necessary for the commissioning, operation, and maintenance of the reactor. In January 1974 AECL and CNEA concluded a Technology Transfer Agreement. The December 1973 contract contained a clause requiring the completion of a safeguards agreement between Argentina and the IAEA before the contract could be implemented. This agreement was concluded in December 1974.

The safeguards relationship between Canada and Argentina has been strongly influenced by the impact of India's "peaceful explosion" in May 1974 on Canada's safeguards policy. That relationship is discussed later.

THE PERIOD 1974-1978

Two developments in the mid-1970s led to a serious questioning of the nonproliferation regime. The first was India's "peaceful nuclear explosion", which to some countries revealed the need for more explicit and comprehensive nonproliferation commitments and safeguards. The second development was the greatly increased interest in nuclear energy, particularly in advanced nuclear technologies, because of the "energy crisis" of 1973-74. Energy self-sufficiency or energy independence became a new, or at least a more attractive, policy objective for many governments.

The quest for greater energy independence by many industrialized countries and several developing ones, especially those without large indigenous uranium reserves, led to much more interest in reprocessing spent fuel to obtain plutonium for recycling in thermal reactors or for eventual use in fast breeder reactors. At the same time it was recognized that India's route to its "peaceful nuclear explosion" had been by the reprocessing of spent fuel from an unsafeguarded research reactor and the use of the separated plutonium for explosive purposes. It became obvious to several countries, therefore, that some specific steps would have to be taken to minimize the perceived proliferation risk associated with reprocessing.

Until this time it had been generally agreed that the separation of plutonium from spent fuel and its subsequent use in recycling was a natural feature of an efficient light-water reactor fuel cycle, as well as an element of policy in the nuclear waste disposal programs of some countries, and a necessary step in the expected development of fast breeder reactors. In fact, the United States had earlier declassified its reprocessing technology in recognition of this general understanding. Some countries which had developed an indigenous reprocessing technology concluded that the export of that technology under IAEA safeguards was acceptable and entered into contracts to do so, for example, the Federal Republic of Germany with Brazil and France with Pakistan.

On the international level, the major result of these new perceptions was the drawing together, largely in response to a Canadian and U.S. initiative, of the major nuclear suppliers - the Nuclear Suppliers Group (NSG) - in an effort to reach agreement on "Guidelines" to cover their nuclear exports. These guidelines were published in a January 1978 Information Circular document issued by the IAEA (INFCIRC 254) and consisted, in brief, of the following principles:

(1) "trigger list" items (nuclear materials, certain other special materials such as heavy water and reactor-grade graphite, and equipment which is considered to be of particular importance in the nuclear fuel cycle from a non-proliferation perspective) should be exported only upon formal assurances explicitly excluding uses which would result in any nuclear explosion;

(2) "trigger list" nuclear materials should be placed under effective physical protection;

(3) "trigger list" items should be exported only when covered by IAEA safeguards;

(4) the export of reprocessing, enrichment, or heavy water production technology or of facilities based on that technology should require the application of IAEA safeguards to any facility employing or drawing upon that technology;

(5) restraint should be exercised in the export of sensitive facilities and technology (reprocessing and enrichment) and of weapons-usable materials;

(6) assurances covering the possible future re-transfer of "trigger list" items should be required by the original suppliers of those items.

The development of the Guidelines of the Nuclear Suppliers Group marked the high-point to date in international co-operation on the nonproliferation safeguards to be applied to nuclear exports by the major supplier nations. These guidelines augment the principles of the IAEA Statute and the NPT, and represent a significant upgrading in the attention to be paid to nonproliferation in the context of international nuclear commerce. However, they fall short in some key respects of Canada's safeguards policy, specifically with regard to Canada's require- ment that NNWS with which Canada is engaged in nuclear co-operation should make a binding commitment to nonproliferation, by becoming states party to the NPT or by an equivalent step, and accept NPT or NPT-type safeguards on all their nuclear activities - in other words, accept full- scope safeguards. Canada advocated forcefully the inclusion of this requirement in the guidelines of the Nuclear Suppliers Group as well as a sanction mechanism to be invoked against those states which might violate their nonproliferation commitments, but was unsuccessful.

CANADA'S NONPROLIFERATION POLICIES: 1974 AND 1976

Canada was one of those countries in which the public's perception of the proliferation risk associated with nuclear exports sharpened greatly after India's "peaceful nuclear explosion" in May 1974. Accordingly, Canada's nonproliferation policy was reviewed, and on December 20, 1974, the government announced more stringent nonproliferation safeguards covering the export of Canadian nuclear and special material, equipment, facilities, and technology to all states, whether NWS or NNWS. The conditions established by this policy were to be applied to all contracts for nuclear exports, including those already approved by the government. They comprised:

(1) a binding assurance that Canadian-origin items would be used exclusively for peaceful, non-explosive purposes;

(2) a binding assurance that Canadian-origin items would be covered by international (IAEA) safeguards for their lifetimes;

(3) a binding assurance that any nuclear material produced by or with Canadian-supplied items would be subject to conditions (1) and (2);

(4) a binding recognition of Canada's right of prior consent over the re-transfer beyond the recipient's jurisdiction of any Canadian-origin items or of any nuclear material used with or produced by those items;

(5) a binding recognition of Canada's right of prior consent over the reprocessing of Canadian-origin nuclear material or of nuclear material irradiated in a Canadian-origin facility as well as over the subsequent storage of any plutonium produced;

(6) a binding recognition of Canada's right of prior consent over the enrichment beyond 20 per cent and the subsequent storage of Canadian-origin uranium;

(7) a binding recognition of Canada's right to apply fall-back safeguards should IAEA safeguards cease to be applied for any reason;

(8) a binding commitment that adequate physical protection measures would be applied.

In implementing this policy, the government announced its intention to permit uranium shipments and other nuclear exports to proceed for a period of one year, pending renegotiation of Canada's nuclear co-operation agreements. This time period was extended for two further six-month terms and so lasted a total of two years.

The re-examination of Canada's safeguards policy continued in the period after December 1974. As a result of this review, the government announced in December 1976 that any new nuclear co-operation would be authorized only for those NNWS which had either ratified the NPT and thereby accepted IAEA safeguards on all their nuclear activities, current and future (accepted full-scope safeguards) -- or made an equally binding commitment to nonproliferation and accepted NPT-type full-scope safeguards. The government also made clear that it would end nuclear co-operation with any state which exploded a nuclear device. This step signalled a significant extension of Canada's safeguards policy to cover all the nuclear activities of its nuclear customers, not merely those using Canadian nuclear supplies. The Canadian government stated that it was prepared to accept any negative commercial consequences that might result from this stringent safeguards policy.

Thus, by December 1976 Canada had developed the most far-reaching national safeguards policy of any nuclear supplier, a policy which went well beyond that of any other state at the time and beyond that subsequently agreed to in the Nuclear Suppliers Group.

IMPLEMENTATION OF THE 1974 AND 1976 POLICIES

(1) The European Economic Community and Japan

By early 1977 agreements incorporating the conditions of Canada's 1974 policy were negotiated with Argentina, the Republic of Korea, Spain, Finland, and Sweden. However, much difficulty was experienced in securing acceptance of these conditions by the European Economic Community (EEC) and Japan, Canada's major uranium markets. The Canadian government decided, therefore, to suspend as of January 1, 1977, all nuclear exports to those countries until they accepted Canada's 1974 policy requirements. This step was a dramatic demonstration of Canada's commitment to nonproliferation and willingness to accept the commercial consequences of its safeguards policy.

The year 1977 was taken up with intensive negotiations with the EEC and Japan directed toward securing acceptance of Canada's 1974 policy requirements. By January 1978 agreement had been reached with Japan on a renegotiated bilateral agreement, and uranium shipments were allowed to proceed. This agreement is now in the process of being ratified. Japan is a party to the NPT and thus meets the requirements of Canada's 1976 policy.

With the EEC, however, negotiations took a different course. Elements of an interim compromise with the EEC on Canada's request for a prior consent right over reprocessing had been identified in discussions in July 1977 between Prime Minister Trudeau and West German Chancellor Helmut Schmidt. It was agreed that, in light of the decision at the (Downing St.) Economic Summit in May 1977 to consider the whole question of reprocessing in an international evaluation of the nuclear fuel cycle, and of the willingness of the EEC to consult with Canada before reprocessing Canadian-origin nuclear material, deliveries of sufficient amounts of Canadian uranium to meet current EEC needs during an interim period could be resumed if all other issues still outstanding in the negotiations were resolved.

In late November and early December of 1977 Canadian negotiators worked out an agreement with the EEC which, except for the interim agreement noted below, met Canada's 1974 policy requirements fully. Under the agreement, the EEC gave Canada a binding assurance with respect to the peaceful non-explosive use of Canadian supplied material, equipment, and material of

any origin produced in Canadian-designed or Canadian-supplied equipment; reaffirmed Canada's prior consent right to the transfer of Canadian-origin supplies outside the EEC; and recognized that all Canadian material, whether supplied directly or through a third country, was subject to the agreement. The settlement allowed France to enrich Canadian uranium for other countries, but excluded Canadian uranium from use in French reactors until France accepted IAEA safeguards on its civil nuclear fuel cycle. (France has since negotiated such an agreement with the IAEA, and as soon as that agreement is in force, will be able to use Canadian uranium in its civil reactors.)

On reprocessing, an interim arrangement along the lines of the Trudeau-Schmidt formula was negotiated to cover the period to the end of the International Nuclear Fuel Cycle Evaluation (INFCE), which had been organized in October 1977. In the interim period, the EEC engaged to consult with Canada before reprocessing Canadian-origin material transferred between December 1974 and the end of the period. Canada also has the right to request such consultations on material transferred before 1974. The reprocessing aspect of the agreement and the corresponding continuation of supply of Canadian uranium are linked to the INFCE, and further negotiations on this question will have to take place during 1980. Canada signed an agreement in September, 1980.

Because responsibility for the transfer of nuclear technology rests with the member states rather than with the EEC, it was agreed that this element of Canadian safeguards policy would be the subject of bilateral agreements between Canada and those member states seeking to acquire Canadian nuclear technology.

The EEC comprises two NWS, the United Kingdom and France, and seven NNWS which are parties to the NPT and thus meet the requirements of Canada's 1976 safeguards policy. The United Kingdom has accepted IAEA safeguards on its total civil nuclear fuel cycle. Once a similar agreement between France and the IAEA becomes effective, France will be in a like position, even though it is not a party to the NPT.

(2) The United States

Co-operation between Canada and the United States in the peaceful uses of nuclear energy has taken place under a 1955 agreement, which was amended slightly in 1956, 1960, and 1962. With the announcement of Canada's 1974 safeguards policy, any uranium shipments to the United States became subject to the conditions of that policy. Two exchanges of notes (March 1976 and November 1977) were negotiated so that Canadian uranium exports to the United States for end-use in that country could take place. With the passage of the US Nuclear Non-Proliferation Act of March 1978, Canadian and American officials have been negotiating a comprehensive amendment to the 1955 agreement as amended which will take into account the upgraded safeguards policies of the two countries.

(3) India

After Canada suspended nuclear co-operation with India in 1974, it tried over the next two years to secure upgraded safeguards arrangements for Canadian-supplied facilities in India, but its efforts proved unsuccessful. As a result, Canada announced in May 1976 that it was terminating its nuclear relationship with India. The two RAPP reactors continue to be subject to safeguards by the IAEA; however, the CIRUS reactor continues to operate free of IAEA safeguards.

(4) Pakistan

Following the announcement of the December 1974 safeguards policy, Canada entered into lengthy negotiations with Pakistan to conclude a bilateral agreement incorporating the requirements of that policy. By December 1976 it was evident that Pakistan was not prepared to meet Canada's requirements and that it was engaged in negotiating the acquisition of a reprocessing facility from France, when there was clearly no need for such a facility given the stage of development of Pakistan's nuclear program. In these circumstances, the Canadian government announced that for all practical purposes nuclear co-operation between Canada and Pakistan was at an end.

The Kanupp reactor continues to be safeguarded by the IAEA.

(5) Argentina

After the "peaceful nuclear explosion" by India in May 1974, Canada requested Argentina to provide a non-explosive use commitment with regard to any material, nuclear material, equipment, facility, and technology supplied by Canada. Argentina provided this commitment in September 1974 and, as required under the December 1973 contract, concluded a safeguards agreement with the IAEA (INFCIRC 224) in early December 1974.

However, in December 1974 the Canadian government announced its updated safeguards policy, which required the conclusion of an agreement between Canada and the recipient country incorporating the conditions of that policy. As acceptance of these new requirements by countries with which Canada was engaged in nuclear co-operation was made essential for all contracts, past and future, to be implemented, Argentina was required to negotiate such a bilateral agreement with Canada covering the Embalse contract. Such an agreement was concluded in January 1976, and in turn it made necessary the negotiation of a new IAEA-Argentina safeguards agreement (INFCIRC 251), a task which was completed in July 1977. This agreement covers the Embalse reactor and would apply to any future nuclear co-operation between Canada and Argentina.

In the midst of this process, Canada announced its December 1976 safeguards policy. While Canada has demonstrated its willingness to co-operate further with Argentina in a broad range of nuclear matters, Argentina has to date not been prepared to meet the requirements of this policy. Argentina has clearly and repeatedly been advised of Canada's December 1976 safeguards policy requirements and of the fact that no further nuclear co-operation between the two countries can take place until Argentina meets the requirements of that policy.

(6) Korea

In 1975 AECL concluded negotiations for the sale to the Republic of Korea of one CANDU reactor, including the technology necessary for its construction and operation. As required under Canada's 1974 safeguards policy, a bilateral nuclear co-operation agreement incorporating the safeguards requirements of that policy was concluded in January 1976. In view of Korea's efforts to obtain a reprocessing facility from France and of other information available at that time, the bilateral agreement was accompanied by an exchange of notes in which Canada stated that with regard to the exercise of its prior consent right over reprocessing Canada "would not be prepared, at this time, to agree to the reprocessing of nuclear material" subject to the agreement. Korea later abandoned its efforts to purchase a reprocessing facility.

Korea acceded to the NPT in April 1975 and in November 1975 concluded an NPT-type safeguards agreement with the IAEA (INFCIRC 153). Therefore, Korea meets the requirements of Canada's 1976 safeguards policy.

(7) Romania

Romania acceded to the NPT in 1970 and concluded a NPT-safeguards agreement with the IAEA in 1972. Moreover, in October 1977 Romania and Canada negotiated a bilateral nuclear co-operation agreement, which was ratified in June 1978. Romania therefore meets the requirements of Canada's 1974 and 1976 safeguards policies.

Within the nonproliferation framework provided by these safeguards agreements, AECL concluded in late 1978 three agreements with the Romanian foreign trade company ROMENERGO covering the licensing of CANDU technology, the supply of engineering services, and the provision of procurement services. The licensing agreement provides ROMENERGO with the right to build one to four 600 MWe CANDU reactors, with a significant amount of components and services being provided by Canadian industry. Under the engineering services agreement, AECL will provide ROMENERGO with design information for a CANDU 600 MWe reactor modified to meet Romania's electrical network. Finally, under the procurement agreement, AECL has agreed to act as ROMENERGO's agent for the sourcing of components for Romania's first CANDU nuclear steam plant.

(8) Australia and Switzerland

Australia and Switzerland are parties to the NPT, so both countries meet the requirements of Canada's 1976 policy. Bilateral agreements with each to implement the requirements of Canada's 1974 policy are being negotiated.

(9) Spain

While Spain has met the requirements of Canada's 1974 policy, it has not yet met those of the 1976 policy. Any new contracts for nuclear co-operation will depend on whether Spain satisfies that condition.

THE IAEA SAFEGUARDS SYSTEM

The IAEA is authorized under Articles III.A.5 and XII of its Statute to establish a system of safeguards to ensure that "assistance provided by it or at its request or under its supervision or control is not used in such a way as to further any military purpose". Since its creation in 1957, the Agency, in co-operation with its member states, has worked steadily to improve the effectiveness of the safeguards operations established under those articles of its Statute. The growth of the Agency's safeguards operations is indicated by the information in Table 1.

Table 1
Growth of the IAEA's Safeguard Activities

Year	Funding (US $)	Professional Person-Years	No. of Member States	No. of Facilities Covered
1964	262 690	10	3	46
1968	661 030	9	11	106
1974	3 400 000	101	37	386
1978	10 900 000	134	43	578

The Agency applies safeguards in four distinct sets of circumstances. First, recipients of assistance from or through the IAEA must agree to accept safeguards on all nuclear material made available through that route. Second, the Agency can, at the request of the states concerned, apply safeguards to supplies being transferred from one state to another. Third, any state can voluntarily submit some or all of its nuclear activities to safeguards. Fourth, parties to international treaties, such as the Treaty of Tlatelolco, the Euratom Treaty, and the NPT, undertake to accept international safeguards to verify their compliance with the treaty in question.

The Agency's safeguards operations are carried out under two types of safeguards agreement:

(1) An agreement (based on INFCIRC 66/Rev. 2) which provides for the application of safeguards to specifically identified materials, nuclear materials, equipment, facilities, and information submitted by the state in question to the application of safeguards;

(2) An agreement (based on INFCIRC 153 or NPT full-scope safeguards) which provides for the application of safeguards to all source or special fissionable material in all peaceful nuclear activities within a state's territory, under its jurisdiction or carried out under its control anywhere for the exclusive purpose of verifying that such material is not diverted to use in connection with nuclear weapons or other nuclear explosive devices.

While the Agency's Statute provides that it will apply safeguards to ensure as far as it can that no military objective will be fulfilled, the purpose of the application has been extended. The IAEA has stated that it interprets this undertaking as including the development, manufacture or testing of nuclear explosive devices of any kind.

As of August 1979, sixty-four NNWS Party to the NPT had concluded the NPT Safeguards Agreement with the IAEA required by Article 3 of the Treaty. Forty-three NNWS Party to the Treaty had not yet done so. In addition, the Agency was applying safeguards under approximately 70 agreements other than those in connection with the NPT. The distinction between these two situations should be clearly recognized. An NPT Safeguards Agreement is comprehensive in nature, i.e. all nuclear material in peaceful nuclear activities is safeguarded, but does not provide for as detailed coverage as an INFCIRC 66/Rev 2, or "facility safeguards" agreement under which materials, equipment, and information as well as nuclear material can be safeguarded. It is widely recognized, however, that the former approach is the more effective, and thus more desirable, safeguards agreement.

Under both types of safeguards agreement, the Agency's primary purpose is to detect whether nuclear material subject to safeguards is being diverted for purposes unknown or for a use not provided for in the applicable safeguards agreement. In a state which has concluded an INFCIRC 153-type safeguards agreement, all nuclear material in all peaceful nuclear activities is under safeguards, and the safeguards agreement therefore applies to nuclear material only. However, in states which have not submitted all their nuclear activities to safeguards, the Agency's safeguards system provides for the application of safeguards to material, equipment, facilities, and information as well as to nuclear material (INFCIRC 66/Rev. 2). Under this approach, the Agency can be requested to apply safeguards to a list of key items (for example, "trigger list" items) so that the location of those items can be identified at any particular time to ensure that any nuclear material which is used in connection with those key items will become subject to safeguards. Agreement by two groups of states has led to the establishment of two such "trigger lists":

(1) the Zangger Committee (called after Professor Zangger of Switzerland who chaired the committee which drew up the list) list is contained in IAEA document INFCIRC 209 and INFCIRC 209 (Mod. 1);

(2) the Nuclear Suppliers Group Guidelines list is contained in IAEA document INFCIRC 254.

These lists are used by those states which have undertaken to apply them in their bilateral dealings. They are now the same as far as material and equipment are concerned. The NSG Guidelines, however, cover certain technologies not included in the Zangger list.

The two principles of IAEA safeguards are the deterrence of covert diversion of nuclear material by the risk of early detection and the minimization of interference in a state's nuclear activities so as to allow the economic and technological development of the state or international co-operation in the field of peaceful nuclear activities, to avoid undue interference in those activities, and to be consistent with prudent management of the facilities concerned. On the basis of these principles, the Agency strives to ensure that the probability of detecting the diversion of a significant quantity of nuclear material is high -- 90 per cent or more and most often 95 per cent.

In pursuing this objective, the Agency has established preliminary definitions of the concepts of "threshold amount", "significant quantity", and "timely detection":

(1) Threshold amount is the approximate quantity of special fissionable material needed for a nuclear explosive device;

(2) Significant quantity is the approximate quantity of nuclear material with respect to which - taking into account any conversion process involved - the possibility of manufacturing a nuclear explosive device cannot be excluded;

(3) Timely detection is, in turn, based on two further concepts: "conversion time", which is defined as the minimum time required to convert different forms of nuclear material to the metallic components of a nuclear explosive device; and "detection time", which is defined as the maximum time which may elapse between a diversion and its detection.

Timeliness of detection and the resulting criteria of frequency-of- inspection are thus essential aspects of the Agency's safeguards operations. The objective of those operations, drawing upon the above concepts and criteria, is to detect on a timely basis the diversion of a significant quantity of nuclear material. The Agency, through both its practical experience and its discussions within the Standing Advisory Group on Safeguards Implementation and other advisory groups, is continuing its efforts to refine further the above concepts and to assign specific values to them.

In the carrying out of its safeguards operations, the Agency independently verifies a state's records of inventories of items under agreements based on INFCIRC 66/Rev. 2 or of nuclear material under agreements based on INFCIRC 153. This verification is done by three means: material accountancy, containment, and surveillance. Material accountancy is the means by which the Agency maintains a current picture of the location and movement of items subject to the safeguards agreement. Containment is the application of locks, seals, and other devices to prevent changes in inventories without the Agency's knowledge. Surveillance includes both human and instrument observations to monitor activities. The application of these three means includes a review of the design of a facility to allow the Agency to identify the features which are relevant to safeguards application.

The objective of the Agency's safeguards operations is to detect diversion to any unauthorized use. If diversion conditions or non-compliance with a safeguards agreement is detected, the Director General of the IAEA informs the Agency's Board of Governors. The Board of Governors then calls upon the state concerned to remedy the non- compliance and also reports the situation to all members of the Agency and to the Security Council and General Assembly of the United Nations (Article XII.C of the IAEA Statute). The key point, however, is that it is the international response to the reported diversion or non-compliance that is considered to be the ultimate deterrent, and this is why timeliness of detection is so important.

Canada has been a strong supporter of the safeguards operations of the IAEA, and Canadian technical experts have participated in advisory groups, technical committees, and other gatherings convened by the Agency to improve those operations. Moreover, Canada has established the Canadian Safeguards Research and Development Program to support the IAEA in its efforts to improve safeguards systems for CANDU reactors. This program has been allocated about $11 million for the period 1978-79 to 1982-83, and work under its auspices is underway.

PHYSICAL PROTECTION

As stated earlier, the risk of horizontal proliferation by the theft and misuse of nuclear material has been widely recognized. In the context of the IAEA, a Group of Experts was convened in 1972, in 1975, and again in 1977 to prepare recommendations to member states on the physical protection of nuclear material. These recommendations, contained in INFCIRC 225/Rev. 1, reflect a large degree of international co-operation in the formulation of physical protection guidelines for use by member states in light of their national situation. This is particularly noteworthy because most, if not all, states regard internal security questions as matters for their consideration alone.

The IAEA also hosted a series of meetings of governmental representatives to draft a Convention on the Physical Protection of Nuclear Material. Agreement on the text of this

Convention has now been achieved, and the Convention itself, which will apply to the physical protection of nuclear material in international transport, will be open for signature in March 1980. Canada signed this in September of 1980.

In the bilateral agreements which Canada negotiates with those countries with which it is engaged in nuclear co-operation, Canada requires the inclusion of a commitment by both parties to ensure that nuclear material involved in those agreements will be subject to effective physical security measures. The standards and recommendations established by or under the sponsorship of the IAEA (for example, INFCIRC 225/Rev. 1) are used as guidelines. The agreements also include provision for consultation on issues of physical security between the parties when necessary.

THE INTERNATIONAL NUCLEAR FUEL CYCLE EVALUATION: 1978-1980

In the mid-1970s a number of American studies, such as the Ford-Mitre Report, resulted in U.S. government policies designed to secure deferrment of reprocessing until there was a demonstrated need for that activity and until the nonproliferation regime had been strengthened so as to minimize the proliferation risk arising from reprocessing. Other governments did not share the U.S. perception, and the resulting differences of opinion required an initiative to resolve the debate. In response to a suggestion by U.S. President Carter, the governments participating in the (Downing St.) Economic Summit in May 1977 agreed that:

> "Our objective is to meet the world's energy needs and to make the peaceful use of nuclear energy widely available, while avoiding the danger of the spread of nuclear weapons. (They) also agreed that, in order to be effective, non-proliferation policies should as far as possible be acceptable to both industrialized and developing countries alike."

On the basis of this agreement, the U.S. government issued an invitation for an Organizing Conference to be held in Washington, D.C., in October 1977. Forty countries, as well as the IAEA, the Commission of the European Communities, the International Energy Agency, and the Nuclear Energy Agency, sent representatives. The countries attending the Organizing Conference agreed that an International Nuclear Fuel Cycle Evaluation (INFCE) should be done to explore the best means of advancing these two objectives:

(1) to make nuclear energy for peaceful purposes widely available to help meet the world's energy requirements;

(2) to take effective measures at the national level and through international agreements to minimize the danger of the proliferation of nuclear weapons without jeopardizing energy supplies or the development of nuclear energy for peaceful purposes.

Thus the INFCE was established to pursue essentially the same objectives as those of the IAEA and the NPT.

The Organizing Conference established guidelines for the structure of the INFCE, in which special consideration was to be given to the specific needs of and conditions in developing countries. This structure consisted of eight working groups open to all interested states, and a technical co-ordinating committee composed of the co-chairmen of the working groups. A Plenary Conference of all participating states was to be held at least once a year. The evaluation was expected to last about two years, with the Final Plenary Conference to be held in late 1979 or early 1980. This Final Plenary Conference took place in Vienna in February 1980.

The eight working groups were each given the task of evaluating a specific aspect of the nuclear fuel cycle. These groups and their country co-chairmen are listed in Table 2.

Canadian experts have participated in the work of seven of the eight working groups - all except working group five. The working groups have drafted their final reports, which are to be submitted for approval to the Final Plenary Conference in February 1980.

It is too early to assess the significance of the INFCE in terms of the nonproliferation objectives. However, attention should be drawn to the views of the Organizing Conference so that expectations about the results of the INFCE will not be unrealistic. The participants of the Washington Conference did not expect that the INFCE would provide definitive answers to the difficult nonproliferation issues currently confronting governments. In fact, they agreed that the "INFCE was to be a technical and analytical study and not a negotiation", with the results

Table 2

INFCE Working Groups and Country Co-Chairmen

Working Group Number	Technical and Economic Scope	Country Co-Chairmen
1	Fuel and heavy water availability	Canada, Egypt, India
2	Enrichment availability	Federal Republic of Germany, France, Iran
3	Assurances of long-term supply of technology, fuel, and heavy water and services in the interest of national needs consistent with nonproliferation	Australia, Philippines, Switzerland
4	Reprocessing, plutonium handling, recycling	Japan, the United Kingdom
5	Fast breeder reactors	Belgium, Italy, the Soviet Union
6	Spent fuel management	Argentina, Spain
7	Waste management and disposal	Finland, Netherlands, Sweden
8	Advanced fuel cycle and reactor concepts	Republic of Korea, Romania, the United States

being transmitted to governments for their consideration. Specifically, the participants were not to be committed to the INFCE's findings and conclusions. Thus the real value of the INFCE will become evident only when it becomes clear how the international community intends to draw upon the considerable amount of work which has gone into the evaluation.

The primary forum in which the post-INFCE international dialogue will take place is the IAEA's Committee on Assurances of Supply (CAS) established by the Agency's Board or Governors in June 1980. The task of this Committee is to consider and advise the Board of Governors on "ways and means in which supplies of nuclear material, equipment and technology and fuel cycle services can be assured on a more predictable and long-term basis in accordance with mutually-acceptable considerations of nonproliferation". While the work programme and priorities of the Committee have not yet been defined it is hoped that the positive dialogue

initiated by INFCE will be continued in its work and that a better nutual understanding of the respective concerns of all countries will result, thereby promoting the evolution of a more effective international nonproliferation regime.

CONCLUSION

The international nonproliferation regime of 1980 is composed of widely varying national policies (Canada's being among the most stringent), of multinational agreements such as the Nuclear Suppliers Group Guidelines, and of international agreements such as the IAEA's Statute and the NPT. The IAEA's safeguards system has been developed as one element of this regime.

The evolution of the current international nonproliferation regime from 1945 to 1980 has entailed the interaction between efforts to formulate a way of "entirely eliminating the use of atomic energy for destructive purposes and promoting its peaceful use for industrial and humanitarian purposes" (Agreed Declaration on Atomic Energy of November 1949). There has been a continuing effort to establish an appropriate balance between these principles, which have been recognized in national policies, in the Statute of the IAEA, in the NPT, and in the INFCE. As nuclear technology becomes more advanced and as more countries establish nuclear programs, the evolution of the nonproliferation regime will continue to require conscientious attention from national governments and the international community.

Glossary

Acid rain: oxides of sulphur and nitrogen combine with hydrogen ions from atmospheric moisture and oxidize during long range, high altitude movement, forming acidic (low pH) compounds which fall as rain or snow.

Actinides: group name for the series of radioactive elements from element 89 (actinium) to element 103 (lawrencium). All are chemically similar and many are long-lived, alpha-emitters.

Adsorption: the adhesion in an extremely thin layer of molecules (as of gases, solutes or liquids) to the surfaces of solid bodies or liquid with which they are in contact.

Advanced Gas-Cooled Reactor (AGR): nuclear power reactor developed mainly in the U.K. and France, using enriched uranium as fuel, carbon dioxide as coolant, and graphite as moderator.

Alpha particle: a heavy particle produced by a radioactive decay process and consisting of two protons and two neutrons, thus carrying two positive charges. It is identical to the nucleus of a helium atom.

Background radiation: the natural ionizing radiation of man's environment including cosmic rays from outer space, naturally radioactive elements in the ground, and naturally radioactive elements in a person's body.

Beta particle: a light particle produced by radioactive decay. It can be either positively (positron) or negatively (negatron) charged, although the latter is more often found. A beta particle is identical to an electron.

Bituminous coal: high quality coal with a high percentage of pure carbon, low ash and low moisture content, and a heat content of approximately 11 000-13 000 Btu/lb.

Boiling Water Reactor (BWR): a nuclear power reactor cooled and moderated by light water and fuelled by enriched uranium. The water is allowed to boil in the core to generate steam which passes directly to the turbine.

Calandria: a cylindrical reactor vessel that contains the heavy water moderator. Hundreds of tubes extend from one end of the calandia to the other, containing the uranium fuel and the pressurized high temperature coolant. The reactor core consists of all the components within the calandria.

CANDU: an acronym for Canada Deuterium Uranium. It refers to a Canadian-type reactor which uses natural uranium fuel and heavy water in the moderator. Pressure tubes containing the fuel and coolant run the length of the reactor vessel or calandria.

Capacity Factor: the ratio of the amount of electrical energy actually generated by a power station in a given period to the amount of electricity which would have been generated if the power station had been operating at full capacity throughout the period.

Closed-cycle cooling: type of cooling for thermal generating stations in which the water used for cooling in the steam cycle is recycled. Either cooling ponds or net evaporative cooling towers are used.

Coal benefication: a method of improving the quality of the coal prior to combustion, as for example in washing.

Commercial in-service date: the date at which a new unit has completed its testing and is turned over to the operators for normal system operation.

Containment: the structures, within and including the reactor building, designed to prevent any material that may escape from the reactor itself from reaching the outside environment. The reactor containment usually consists of steel and thick concrete.

Control rods: rod of neutron-absorbing material inserted into the reactor core to soak up neutrons and control the rate of fission reaction.

Coolant: a liquid or gas circulated through the core of a reactor to extract the heat of the fission process. In a CANDU reactor, this is heavy water.

Cooling tower: structure related to generating stations in which warm water from the cooling cycle is cooled by ambient air. It can be wet or dry, natural or mechanical draft.

Core: the central part of a nuclear reactor containing the fuel rods, moderator and control rods. The nuclear fission reactions take place and the resultant heat is generated within the core.

Curie(Ci): the unit of activity of a radioactive material. One curie is equivalent to 3.7×10^{10} disintegrating nuclei, or nuclear transformations per second (dps).

1 millicurie (mCi) = 3.7×10^{7} dps
1 microcurie (uCi) = 3.7×10^{4} dps
1 picocurie (pCi) = 3.7×10^{-2} dps

Decay: the decrease in activity of a radioactive material as it spontaneously transforms itself.

Declining block rate structure: a rate structure which has generally been used in pricing of electricity in which consumption is divided into blocks of use, with each succeeding block being cheaper.

Derived emission level: a calculation of radioactive emissions from nuclear installations, based upon population density, wind velocity and direction, etc., which could result in general exposure levels no higher than those set out in the regulations.

Deuterium: an isotope of hydrogen containing one proton and one neutron in the nucleus. Chemically it is similar to hydrogen, but it has different physical and nuclear properties. Its natural abundance is about one part in 7 000 of hydrogen in the form of heavy water (D_2O). It is the most effective neutron moderator available for reactors.

Discount rate: a rate of interest representing the time-related value of resources. It is used to convert costs that occur at any given time to equivalent values at a specified time, for comparison purposes.

Dousing System: a system which reduces pressure within the containment buildings by condensing the steam with water sprays.

Econometric model: application of statistical methods to the study of economic data and problems.

Electro-static precipitator: device in which particles of fly ash are charged electrically and then attracted to a collection surface as they pass through an electrical field. Collection efficiencies can be over 99.5 per cent and are very high for very small particle sizes as well as for large particulate sizes.

Emergency core cooling system: system of getting light water to the core of a nuclear reactor to rewet and cool the fuel. Available in case of a disruption in the normal cooling system.

Enriched Uranium: uranium in which the content of the fissile isotope, uranium-235, is higher than the 0.71 per cent normally found in nature. Enriched uranium, containing 2-4 per cent of uranium-235, is used as fuel in many types of reactors.

Epidemiological study: a study of populations dealing with the incidence, distribution, and control of disease in that population.

Equity: excess of assets over liabilities.

External exposure: irradiation of biological systems from radiation sources outside of the organism.

Fission: the splitting of an atomic nucleus with the release of energy.

Fission products: the smaller atoms that result from the fission of larger atoms such as uranium-235.

Flat rate pricing: the pricing of a commodity, e.g., electricity, at the same rate no matter how much is used.

Flue gas desulfurization: a method of removing the sulphur oxides from the gas emitted by the burning of coal by bringing the flue gas in contact with a chemical absorbent which reacts with the SO_2 to produce a slurry containing dissolved or solidified sulphur.

Gamma ray: a form of electromagnetic radiation similar to light and distinguished by its high energy, high penetration power and short wave length. It is produced during radioactive decay.

Gas-cooled reactor: a nuclear reactor in which a gas, such as carbon dioxide, is used as the coolant.

Genetic effect: a radiation effect which manifests itself in the descendents of the exposed individual.

Geothermal well pair: term used to describe production and reinjection wells drilled. Once the energy has been extracted from the production fluid or vapour, the remaining brine is then reinjected.

Half-life: the period required for the disintegration of half of the atoms in a given amount of a specific radioactive substance.

Heat transport system: those parts of a nuclear power reactor which are involved in the transfer of heat energy from the fuel to the fluid medium used to derive the electrical generator.

Heavy water: water in which the hydrogen atoms are the heavy hydrogen isotope, deuterium. It is sometimes called deuterium oxide.

High level radioactive waste: the most highly contaminated waste from the nuclear fuel cycle. It includes most of the fission products from irradiated fuel, plus small amounts of unseparated uranium and plutonium plus the greater proportion of the actinides produced in the reactor. It usually contains millions of curies per cubic metre.

Internal exposure: irradiation of biological systems from radionuclides within the organism.

Ionizing radiation: radiation which, by reason of its nature and energy, interacts with matter to remove electrons from (ionize) the atoms of material absorbing it, producing electrically charged atoms which are called ions.

Irradiated fuel: reactor fuel which has been involved in a chain reaction and has thereby accumulated fission products; in any application, exposed to radiation. Also called 'spent' fuel.

Isotope: one of perhaps several different species of a given chemical element, distinguished by variations in the number of neutrons in the atomic nucleus but indistinguishable by chemical means.

Kilowatt (kW): one thousand watts. A unit of electric power.

Kilowatt hour (kWh): a unit of energy equal to the work done by one kilowatt acting for one hour.

Leachate: a solution or product obtained by percolating liquid (as water) in order to separate the soluble components.

Lead time: time needed to plan and construct a facility, including the time required to obtain government approval, carry out environmental assessment, etc.

LET: Linear Energy Transfer refers to the density of ionization events along the path of a nuclear particle.

Light Water Reactor: a nuclear reactor which uses light (or ordinary) water as a moderator and coolant and enriched uranium as fuel.

Linear relationship: as in the effects of radiation - a relationship which follows in a direct or straight line from lowest to highest.

Load management: a method of controlling electrical demand by switching off, or moving, the demand from one time period to another.

LOCA (Loss of Coolant Accident): an event in which coolant is escaping from the heat transport system at a rate which is greater than the capacity of the normal system designed to keep the heat transport system full.

Low head hydro: hydroelectric development in which the head, or difference between in elevation, is less than 40 metres. This type of development is generally on the course of a river with little or no long-term shortage. Also includes run-of-the-river hydro.

Low level radioactive wastes: slightly contaminated wastes from the nuclear fuel cycle, such such as housekeeping materials, scrap materials, and used protective clothing. They usually contain a few curies per cubic metre.

LWR: See Light Water Reactor.

Marginal cost pricing: a method of setting prices in which price is made equal to marginal cost, e.g., the cost of producing the last unit of the output.

Medium level radioactive waste: wastes from the nuclear fuel cycle which are moderately contaminated. These consist of materials such as air filters, water purification resins, etc., usually containing thousands of curies per metre.

Megawatts (MW, (MW)e, MW(th)): one megawatt is a unit of power equal to one thousand kilowatts. MW(th) denotes the thermal power of a power station, that is, the rate at which heat is produced (by fission in the reactor core if it is a nuclear power station). MW(e) denotes the electrical power output of the station and is only a fraction of the thermal power - typically about 30 per cent of a heavy water reactor and up to 40 per cent for a modern fossil fuel-powered station. This ratio is also called the thermal efficiency of the power station.

Moderator: a material used in a reactor core to slow down fast neutrons, without unduly absorbing them, so as to increase the probability of the neutrons causing fission in a uranium-235 or plutonium-239 nucleus.

Net cash flow: cash left after taxes have been paid, expenditures on repairs and maintenance carried out, any necessary adjustments to working capital, and account is taken of any residual values of assets or other miscellaneous income.

Neutron: an uncharged particle which is a constituent of the nucleus of all nuclides except hydrogen.

Off-peak power: electricity used in periods of low demand.

Once-through: term used in the utility context for: a) once-through cooling - used to process cooling water only once; b) use of uranium fuel in a reactor only once (the fuel is not reprocessed).

Overburden: material overlying a deposit of useful geologic materials.

Peak load pricing: pricing for a product in which the highest charge is at the time when the demand is highest.

Pluton: large body of intrusive igneous (formed from molten) rock.

Pressure Relief Valves: valves which, under accident conditions, would open automatically to connect the building housing, the reactor to the vacuum building.

Pressurized Water Reactor(PWR): a power reactor cooled and moderated by light water in a pressure vessel surrounding the core. The water is pressurized to prevent boiling in a closed primary loop and is circulated through a heat exchanger which generates steam in a secondary loop connected to the turbine. Enriched uranium is used as fuel.

Pressurizer: the unit in the primary loop circuit of some CANDU reactors that pressurizes the heavy water coolant to prevent boiling.

Process system: those systems in a nuclear generating station related to the removal of heat from the core and the production of electricity. The main systems involved are the heat transport system, the moderator system, the regulating system, the electrical and fuel-handling system, the turbine-generator system, and the reactor structure and other related buildings.

Proton: a positively charged particle which is a constituent of the nucleus of all nuclides.

Rad: the unit of absorbed dose of ionizing radiation. The rad represents a unit energy imported to matter by ionizing radiation per unit mass of the irradiated matter. It corresponds to 0.01 joules of energy per kg of material.

Radioactivity: the spontaneous decay of an unstable atomic nucleus into one or more different elements or isotopes. It involves the emission of particles of spontaneous fission until a stable state is reached. Radio-activity produces radiation - the two terms are not equivalent.

Radionuclide: a radioactive nuclide (atom).

Radon daughter: decay product of radon gas, an inert gas given off from radioactive uranium.

Reactor: an assembly of nuclear fuel that can sustain a controlled chain reaction based on nuclear fission.

Reactor-year: the unit of time which a single reactor unit has been operating.

Rem: the unit of dose equivalence. The dose equivalent is equal to the absorbed dose (in rads) multiplied by any quality or modifying factors involved in a specific irradiating situation. One millirem equals one-thousandth of a rem.

Safety system: those systems in a nuclear generating station which provide the shutdown mechanisms in case of malfunction of the process system. They included the shutdown system(s), the shutoff rods, the injection water system or emergency coolant system (ECC), the containment system, the dump tank and related valves, the spray or dousing system in the calandria, and the vacuum building. As each of the CANDU reactors now operating is different, they do not all apply to each reactor.

SGWR: See Steam-Generated Heavy Water Reactor.

Slurry: a free-flowing pumpable suspension of fine solid material in a liquid. A slurry pipeline is one method of transporting coal.

Somatic effects: effects produced by radiation in the body of the person irradiated, usually cancers.

Spent fuel: see Irradiated Fuel.

Steam-Generating Heavy Reactor(SGHWR): a nuclear power reactor using heavy water as moderator, light water as coolant and enriched uranium as fuel.

Stochastic effect: random chance or probability.

Tailings: the waste material from a uranium mill after the uranium has been extracted from the ore. Tailings contain the radioactive decay products of uranium mixed with a large volume of non-radioactive rock, all in a finely ground form and mixed with water.

Tails Assay: refers to the proportion of fissionable U-235 remaining in the depleted uranium after enrichment (the tails). It can be varied as a product decision, e.g., the higher the tails assay, the greater is the amount of uranium feed required per unit of enriched uranium product.

Thermal coal: coal burned to produce heat, for example, for electrical generation and industrial processes; it will yield gaseous fuels by gasification processes and liquid fuels by liquefaction process.

Thermal plant: a station for generating electrical energy from thermal sources. A thermal plant may have fossil-fuelled steam turbines, fossil-fuelled combustion turbines, or nuclear steam turbines.

Threshold: a dose level below which no effect is encountered.

Time-of-use pricing: method of charging for the electricity or other service used which takes into consideration both the time of day at which it is used and the season of the year.

Tonne: one metric ton equals 2204.6 pounds.

Uranium: a heavy, slightly radioactive metallic element with an atomic number of 92. As found in nature, it is a mixture of the isotopes U-235 (0.7 per cent) and U-238 (99.3 per cent). The artificially produced U-233 and the naturally occuring U-235 are fissile. U-238 is fertile.

Uranium dioxide (UO_2): used with the natural concentration of U-235 unchanged as the fuel in CANDU power reactors because of its chemical and radiation stability, good gaseous fission product retention, and high melting point.

Working level month: unit of exposure used in uranium mines and equivalent to a rem, which combines the concentration of radon daughters in the air with the length of exposure.

Yellowcake: a chemical concentrate produced from uranium ore by an extraction process in a uranium mill; normally such concentrations contain about 85 per cent U_3O_8 (70 per cent elemental uranium).

Zirconium: a naturally occuring metallic element with an atomic number of 40. The material is used extensively in the construction of in-core reactor components because it has a very high corrosion resistance to high temperature water with low neutron absorption.